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 **March 31, 2009**
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. has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ___ *No* ___

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 has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ___ *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 April 30, 2009
American Electric Power Company, Inc.	476,760,862
	($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
March 31, 2009

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.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APB	Accounting Principles Board Opinion.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
E&R	Environmental compliance and transmission and distribution system reliability.
EaR	Earnings at Risk, a method to quantify risk exposure.
EIS	Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates under FIN 46R.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
ENEC	Expanded Net Energy Cost.
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
ESP	Electric Security Plan.
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."

Term	Meaning
FSP	FASB Staff Position.
FSP FIN 39-1	FSP FIN 39-1, “Amendment of FASB Interpretation No. 39.”
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JBR	Jet Bubbling Reactor.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP Consolidated’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.
PATH	Potomac Appalachian Transmission Highline, LLC and its subsidiaries, a joint venture with Allegheny Energy Inc. formed to own and operate electric transmission facilities in PJM.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
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.
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.
SEC	United States Securities and Exchange Commission.

Term	Meaning
SECA	Seams Elimination Cost Allocation.
SEET	Significant Excess Earnings Test.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, “Accounting for the Effects of Certain Types of Regulation.”
SFAS 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”
SFAS 157	Statement of Financial Accounting Standards No. 157, “Fair Value Measurements.”
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TCRR	Transmission Cost Recovery Rider.
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:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms.
- 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 including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner.
- 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 and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances.
- 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.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Economic Slowdown

The financial struggles of the U.S. economy continue to impact our industrial sales as well as sales opportunities in the wholesale market. Industrial sales in various sections of our service territories are decreasing due to reduced shifts and suspended operations by some of our large industrial customers. Although many sections of our service territories are experiencing slowdowns in new construction, our residential and commercial customer base appears to be stable. As a result of these economic issues, we are currently monitoring the following:

- Margins from Off-system Sales - Margins from off-system sales continue to decrease due to reductions in sales volumes and weak market power prices, reflecting reduced overall demand for electricity. We currently forecast that off-system sales volumes will decrease by approximately 30% in 2009. These trends will most likely continue until the economy rebounds and electricity demand and prices increase.

- Industrial KWH Sales - Industrial KWH sales for the quarter ended March 31, 2009 were down 15% in comparison to the quarter ended March 31, 2008. Approximately half of this decrease was due to cutbacks or closures by six of our large metals customers. We also experienced additional significant decreases in KWH sales to customers in the plastics, rubber, auto and paper manufacturing industries. Since our trends for industrial sales are usually similar to the nation's industrial production, these trends are likely to continue until industrial production improves.

- Risk of Loss of Major Customers - We monitor the financial strength and viability of each of our major industrial customers individually. We have factored this analysis into our operational planning. Our largest customer, Ormet, an industrial customer with a 520 MW load, recently announced that it is in dispute with its sole customer which could potentially force Ormet to halt production.

Capital Markets

The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact our access to capital, liquidity, asset valuations in our trust funds, the creditworthy status of customers, suppliers and trading partners and our cost of capital. We actively manage these factors with oversight from our risk committee. We cannot predict the length of time the current credit market situation will continue or its impact on future operations and our ability to issue debt at reasonable interest rates. Despite the current volatile markets, we were able to issue approximately $1 billion of long-term debt in the first quarter of 2009 and $1.64 billion (net proceeds) of AEP common stock in April 2009.

We believe that we have adequate liquidity to support our planned business operations and construction program for the remainder of 2009 due to the following:

- As of March 31, 2009, we had $2.2 billion in aggregate available liquidity under our credit facilities. These credit facilities include 27 different banks with no one bank having more than 10% of our total bank commitments. In April 2009, we allowed $350 million of our credit facility commitments to expire. As of March 31, 2009, cash and cash equivalents were $710 million.
- Of our $17 billion of long-term debt as of March 31, 2009, approximately $300 million will mature during the remainder of 2009 (approximately 1.8% of our outstanding long-term debt as of March 31, 2009). The $300 million of remaining 2009 maturities exclude payments due for securitization bonds which we recover directly from ratepayers.

- In April 2009, we issued 69 million shares of common stock at $24.50 per share for net proceeds of $1.64 billion. We used $1.25 billion of the proceeds to repay part of the cash drawn under our credit facilities. These transactions improved our debt to capital ratio to 58.1% assuming no other changes from our March 31, 2009 balance sheet. With the remaining proceeds, we intend to pay down other existing debt. These actions will help to support our investment grade ratings and maintain financial flexibility.
- We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations.

Approximately $1.7 billion of outstanding long-term debt will mature in 2010, excluding payments due for securitization bonds which we recover directly from ratepayers. We intend to refinance or repay our debt maturities.

We sponsor several trust funds with significant investments intended to provide for future payments of pensions, OPEB, nuclear decommissioning and spent nuclear fuel disposal. Although all of our trust funds' investments are diversified and managed in compliance with all laws and regulations, the value of the investments in these trusts declined substantially over the past year due to decreases in domestic and international equity markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. The decline in pension asset values will not require us to make a contribution under ERISA in 2009. We estimate that we will need to make minimum contributions to our pension trust of $475 million in 2010 and $283 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

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 March 31, 2009, our credit exposure net of collateral was approximately $825 million of which approximately 89% is to investment grade counterparties. At March 31, 2009, our exposure to financial institutions was $42 million, which represents 5% of our total credit exposure net of collateral (all investment grade).

Regulatory Activity

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to recover financing costs related to the construction of the Stall and Turk generating facilities. These financing costs are currently being capitalized as AFUDC in Arkansas. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

In March 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESP filings. If accepted by CSPCo and OPCo, the ESPs would be in effect through 2011. Among other things, the ESP order authorized capped increases to revenues during the three-year ESP period and also authorized a fuel adjustment clause (FAC) which allows CSPCo and OPCo to phase-in and defer actual fuel costs incurred, along with purchased power and related expenses that will be trued-up, subject to annual caps and prudency and accounting reviews. Deferred phase-in regulatory asset balances for fuel costs not currently recovered due to the cap are expected to be material. The projected revenue increases for CSPCo and OPCo are listed below:

	Projected Revenue Increases		
	2009	**2010**	**2011**
		(in millions)	
CSPCo	$ 116	$ 109	$ 116
OPCo	130	125	153

The above revenues include some incremental cost recoveries. In addition to the revenue increases, net income will be positively affected by the material noncash phase-in deferrals from 2009 through 2011. These deferrals will be collected from 2012 through 2018.

For additional details related to the ESPs, see the "Ohio Electric Security Plan Filings" section of "Significant Factors."

In March 2009, the IURC approved the settlement agreement with I&M with modifications that provides for an annual increase in revenues of $42 million, including a $19 million increase in revenue from base rates and $23 million in additional tracker revenues for certain incurred costs, subject to true-up.

In March 2009, APCo and WPCo filed an annual ENEC filing with the WVPSC for an increase of approximately $442 million for incremental fuel, purchased power and environmental compliance project expenses, to become effective July 2009. In March 2009, the WVPSC issued an order suspending the rate increase request until December 2009. In April 2009, APCo and WPCo filed a motion for approval of a provisional interim ENEC increase of $156 million, effective July 2009 and subject to refund pending the adjudication of the ENEC by December 2009.

Capital Expenditures

Due to recent capital market instability and the economic slowdown, we reduced our planned capital expenditures for 2010 from $3.4 billion to $1.8 billion:

	2010 Capital Expenditure Budget	
	(in millions)	
New Generation	$	251
Environmental		252
Other Generation		431
Transmission		290
Distribution		552
Corporate		70
Total	$	1,846

We also reduced our 2011 environmental capital expenditure projection from $892 million to $246 million. We intend to keep operation and maintenance expense relatively flat in 2009 in comparison to 2008. We do not believe that these cutbacks will jeopardize the reliability of the AEP System.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

Fuel Costs

For 2009, we expect our coal costs to increase by approximately 12%. With the recent ESP orders for CSPCo and OPCo, we now have active fuel cost recovery mechanisms in all of our jurisdictions. The deferred fuel balances of CSPCo and OPCo at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. As of March 31, 2009, CSPCo and OPCo had a combined $83 million under-recovered fuel balance, including carrying costs. We expect this amount to increase significantly over the remainder of 2009. Depending upon certain variables, including the potential escalation of fuel costs and the timing of the economic recovery, this amount may continue to increase in 2010 and 2011.

Recent coal consumption and projected consumption for the remainder of 2009 have decreased significantly. As a result, we are in discussions with our coal suppliers in an effort to better match deliveries with our current consumption trends and to minimize the impact on fuel inventory costs.

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

- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 38% of the barging is for the transportation of agricultural products, 30% for coal, 13% for steel and 19% for other commodities.

Generation and Marketing

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

The table below presents our consolidated Net Income by segment for the three months ended March 31, 2009 and 2008.

	Three Months Ended March 31, 2009	2008
	(in millions)	
Utility Operations	$ 346	$ 413
AEP River Operations	11	7
Generation and Marketing	24	1
All Other (a)	(18)	155
Net Income	$ 363	$ 576

(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 settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP Consolidated

First Quarter of 2009 Compared to First Quarter of 2008

Net Income in 2009 decreased $213 million compared to 2008 primarily due to income of $164 million (net of tax) in 2008 from the cash settlement of a power purchase and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006 and a decrease in Utility Operations segment earnings of $67 million. The decrease in Utility Operations segment net income primarily relates to lower off-system sales margins due to lower sales volumes and lower market prices which reflect weak market demand.

Average basic shares outstanding increased to 407 million in 2009 from 401 million in 2008 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. In 2008, we contributed 1.25 million shares of common stock held in treasury to the AEP Foundation. The AEP Foundation is an AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP's subsidiaries operate. Actual shares outstanding were 408 million as of March 31, 2009. In April 2009, we issued 69 million shares of AEP common stock at $24.50 per share for total net proceeds of $1.64 billion.

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.

	Three Months Ended March 31,	
	2009	**2008**
	(in millions)	
Revenues	$ 3,267	$ 3,294
Fuel and Purchased Power	1,196	1,213
Gross Margin	2,071	2,081
Depreciation and Amortization	373	355
Other Operating Expenses	994	941
Operating Income	704	785
Other Income, Net	30	43
Interest Charges	220	208
Income Tax Expense	168	207
Net Income	$ 346	$ 413

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three Months Ended March 31, 2009 and 2008

	2009	**2008**
Energy Summary	**(in millions of KWH)**	
Retail:		
Residential	14,368	14,500
Commercial	9,395	9,547
Industrial	12,126	14,350
Miscellaneous	576	609
Total Retail	36,465	39,006
Wholesale	6,777	11,742
Texas Wires – Energy Delivered to Customers Served by TNC and TCC in ERCOT	5,738	5,823
Total KWHs	48,980	56,571

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. Cooling degree days and heating degree days in our service territory for the three months ended March 31, 2009 and 2008 were as follows:

	2009	2008
Weather Summary	**(in degree days)**	
Eastern Region		
Actual – Heating (a)	1,900	1,830
Normal – Heating (b)	1,791	1,767
Actual – Cooling (c)	5	-
Normal – Cooling (b)	3	3
Western Region (d)		
Actual – Heating (a)	854	941
Normal – Heating (b)	905	931
Actual – Cooling (c)	38	26
Normal – Cooling (b)	20	20

(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.

First Quarter of 2009 Compared to First Quarter of 2008

Reconciliation of First Quarter of 2008 to First Quarter of 2009
Net Income from Utility Operations
(in millions)

First Quarter of 2008		$ 413
Changes in Gross Margin:		
Retail Margins	61	
Off-system Sales	(136)	
Transmission Revenues	4	
Other Revenues	61	
Total Change in Gross Margin		(10)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(56)	
Gain on Dispositions of Assets, Net	3	
Depreciation and Amortization	(18)	
Interest Income	(10)	
Carrying Costs Income	(8)	
Other Income, Net	5	
Interest Expense	(12)	
Total Change in Operating Expenses and Other		(96)
Income Tax Expense		39
First Quarter of 2009		$ 346

Net Income from Utility Operations decreased $67 million to $346 million in 2009. The key drivers of the decrease were a $10 million decrease in Gross Margin and a $96 million increase in Operating Expenses and Other, partially offset by a $39 million decrease in Income Tax Expense.

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

- Retail Margins increased $61 million primarily due to the following:
  - A $58 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $17 million increase in base rates in Oklahoma, a $13 million increase related to the net increases in Ohio as a result of the PUCO's approval of our Ohio ESPs and a $5 million net rate increase for I&M.
  - A $54 million increase resulting from reduced sharing of off-system sales margins with retail customers in our eastern service territory due to a decrease in total off-system sales.
  - A $6 million increase in fuel margins in Ohio due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the recovery of fuel and related costs during the ESP period. See "Ohio Electric Security Plan Filings" section of Note 3.

  These increases were partially offset by:
  - A $58 million decrease in fuel margins related to an OPCo coal contract amendment recorded in 2008 which reduced future deliveries to OPCo in exchange for consideration received.
  - A $32 million decrease in margins from industrial sales due to reduced shifts and suspended operations by some of the large industrial customers in our service territories.
  - A $20 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
- Margins from Off-system Sales decreased $136 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading margins.

- Other Revenues increased $61 million primarily due to Cook Plant accidental outage insurance policy proceeds of $54 million. Of these insurance proceeds, $20 million were used to offset fuel costs associated with the Cook Plant Unit 1 shutdown. This increase in revenues was offset by a corresponding decrease in Retail Margins as discussed above. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

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

- Other Operation and Maintenance expenses increased $56 million primarily due to the following:
  - An $80 million increase related to the deferral of Oklahoma ice storm costs in 2008 resulting from an OCC order approving recovery of January and December 2007 ice storm expenses.
  - A $38 million increase related to storm restoration expenses, primarily in our eastern service territory.
  - A $15 million increase related to an obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of CSPCo's and OPCo's ESPs. See "Ohio Electric Security Plan Filings" section of Note 3.

  These increases were partially offset by:
  - A $34 million decrease in employee-related expenses.
  - A $14 million decrease in plant outage and other maintenance expenses.
  - A $13 million decrease in tree trimming, reliability and other transmission and distribution expenses.
  - A $10 million decrease 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.
- Depreciation and Amortization increased $18 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- Interest Income decreased $10 million primarily due to the 2008 favorable effect of claims for refund filed with the IRS.
- Carrying Costs Income decreased $8 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Interest Expense increased $12 million primarily due to increased long-term debt and higher interest rates on variable rate debt.
- Income Tax Expense decreased $39 million due to a decrease in pretax income.

AEP River Operations

First Quarter of 2009 Compared to First Quarter of 2008

Net Income from our AEP River Operations segment increased from $7 million in 2008 to $11 million in 2009 primarily due to lower fuel costs and gains on the sale of two older towboats. These increases were partially offset by lower revenues due to reduced import volumes and lower freight rates.

Generation and Marketing

First Quarter of 2009 Compared to First Quarter of 2008

Net Income from our Generation and Marketing segment increased from $1 million in 2008 to $24 million in 2009 primarily due to higher gross margins from marketing activities.

All Other

First Quarter of 2009 Compared to First Quarter of 2008

Net Income from All Other decreased from income of $155 million in 2008 to a loss of $18 million in 2009. In 2008, we had after-tax income of $164 million from a litigation settlement of a power purchase and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. 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.

AEP System Income Taxes

Income Tax Expense decreased $114 million in the first quarter of 2009 compared to the first quarter of 2008 primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	March 31, 2009		December 31, 2008	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 16,843	56.5%	$ 15,983	55.6%
Short-term Debt	1,976	6.6	1,976	6.9
Total Debt	18,819	63.1	17,959	62.5
Preferred Stock of Subsidiaries	61	0.2	61	0.2
AEP Common Equity	10,940	36.6	10,693	37.2
Noncontrolling Interests	18	0.1	17	0.1
Total Debt and Equity Capitalization	$ 29,838	100.0%	$ 28,730	100.0%

As of March 31, 2009, our ratio of debt-to-total capital was 63.1%. After the issuance of 69 million new common shares and the application of the net proceeds of $1.64 billion to reduce debt, our pro forma ratio of debt-to-capital as of the date of issuance would have been 57.6%.

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 or common stock.

Capital Markets

In 2008, the domestic and world economies experienced significant slowdowns. The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact our access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications since we rely on continuing access to capital to fund operations and capital expenditures. We cannot predict the length of time the credit situation will continue or its impact on future operations and our ability to issue debt at reasonable interest rates.

We believe we have adequate liquidity through 2009 under our existing credit facilities. However, the current credit markets could constrain our ability to issue commercial paper. Approximately $300 million (excluding payments due for securitization bonds which we recover directly from ratepayers) of our $17 billion of long-term debt as of March 31, 2009 will mature during the remainder of 2009. We intend to refinance debt maturities. At March 31, 2009, we had $3.9 billion ($3.6 billion after an April expiration of one facility) in aggregate credit facility commitments to support our operations. These commitments include 27 different banks with no one bank having more than 10% of our total bank commitments.

During the first quarter of 2009, we issued $475 million of 7% senior notes due 2019, $350 million of 7.95% senior notes due 2020, $100 million of 6.25% Pollution Control Bonds due 2025 and $34 million of 5.25% Pollution Control Bonds due 2014.

During 2008, we chose to begin eliminating our auction-rate debt position due to market conditions. As of March 31, 2009, $272 million of our auction-rate tax-exempt long-term debt (rates range between 1.676% and 13%) remained outstanding with rates reset every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. Approximately $218 million of the $272 million of outstanding auction-rate debt relates to a lease structure with JMG that we are unable to refinance without JMG's consent. The rates for this debt are at contractual maximum rates of 13%. The initial term for the JMG lease structure matures on March 31, 2010. We are evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At March 31, 2009, our available liquidity was approximately $2.2 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)(b)	April 2009
Total		3,919		
Cash and Cash Equivalents		710		
Total Liquidity Sources		4,629		
Less: Cash Drawn on Credit Facilities		1,969	(c)	
Letters of Credit Issued		492		
Net Available Liquidity	$	2,168		

(a) Reduced by Lehman Brothers Holdings Inc.'s commitment amount of $81 million following its bankruptcy.
(b) Expired in April 2009.
(c) Paid $1.25 billion with proceeds from the equity issuance in April 2009.

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. The credit facilities allow for the issuance of up to $750 million as letters of credit under each credit facility.

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 March 31, 2009, we had credit facilities totaling $3 billion to support our commercial paper program. In 2008, we borrowed $2 billion under these credit facilities at a LIBOR rate. In April 2009, we repaid $1.25 billion of the $2 billion borrowed under the credit facilities. The maximum amount of commercial paper outstanding during 2009 was $308 million. The weighted-average interest rate for our commercial paper during 2009 was 1.22%. No commercial paper was outstanding at March 31, 2009.

As of March 31, 2009, under the $650 million 3-year credit agreement reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million following its bankruptcy, letters of credit of $372 million were issued to support variable rate Pollution Control Bonds.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At March 31, 2009, this contractually-defined percentage was 59.1%. Nonperformance of these covenants could result in an event of default under these credit agreements. At March 31, 2009, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At March 31, 2009, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 396 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.41 per share in April 2009. 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 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 cash flows, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

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

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

In 2009, Moody's:

- Placed AEP on negative outlook due to concern about overall credit worthiness, pending rate cases and recessionary pressures.
- Placed OPCo, SWEPCo, TCC and TNC on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries.
- Affirmed the stable rating outlooks for CSPCo, I&M, KPCo and PSO.
- Changed the rating outlook for APCo from negative to stable due to recent rate recoveries in Virginia and West Virginia.

In 2009, Fitch:

- Affirmed its stable rating outlook for I&M, PSO and TNC.
- Changed its rating outlook for TCC from stable to negative.

If we receive a downgrade in our credit ratings by any of the rating agencies, 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.

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 411	$ 178
Net Cash Flows from Operating Activities	317	631
Net Cash Flows Used for Investing Activities	(727)	(894)
Net Cash Flows from Financing Activities	709	240
Net Increase (Decrease) in Cash and Cash Equivalents	299	(23)
Cash and Cash Equivalents at End of Period	$ 710	$ 155

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(in millions)	
Net Income	$ 363	$ 576
Depreciation and Amortization	382	363
Other	(428)	(308)
Net Cash Flows from Operating Activities	$ 317	$ 631

Net Cash Flows from Operating Activities decreased in 2009 primarily due to a decline in net income and an increase in fuel inventory.

Net Cash Flows from Operating Activities were $317 million in 2009 consisting primarily of Net Income of $363 million and $382 million 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 resulted in lower cash from operations due to an increase in coal inventory from December 31, 2008.

Net Cash Flows from Operating Activities were $631 million in 2008 consisting primarily of Net Income of $576 million and $363 million 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 resulted in lower cash from operations due to payment of items accrued at December 31, 2007.

Investing Activities

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(in millions)	
Construction Expenditures	$ (897)	$ (778)
Proceeds from Sales of Assets	172	18
Other	(2)	(134)
Net Cash Flows Used for Investing Activities	$ (727)	$ (894)

Net Cash Flows Used for Investing Activities were $727 million in 2009 and $894 million in 2008 primarily due to Construction Expenditures for our new generation, environmental and distribution investment plan. Construction Expenditures increased compared to 2008 due to expenditures for new generation during 2009. Proceeds from Sales of Assets in 2009 primarily includes $104 million in progress payments for Turk Plant construction from the joint owners.

In our normal course of business, we purchase investment securities including variable rate demand notes with cash available for short-term investments and purchase and sell securities within our nuclear trusts. The net amount of these activities is included in Other.

We forecast approximately $2.6 billion of construction expenditures for all of 2009, excluding AFUDC. 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 net income and financing activities.

Financing Activities

	Three Months Ended March 31, 2009	2008
	(in millions)	
Issuance of Common Stock	$ 48	$ 45
Issuance/Retirement of Debt, Net	854	376
Dividends Paid on Common Stock	(169)	(167)
Other	(24)	(14)
Net Cash Flows from Financing Activities	$ 709	$ 240

Net Cash Flows from Financing Activities in 2009 were $709 million primarily due to the issuance of $825 million of senior unsecured notes and $134 million of pollution control bonds. See Note 9 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2008 were $240 million primarily due to the issuance of $315 million of junior subordinated debentures and $500 million of senior unsecured notes, partially offset by the retirement of $95 million of pollution control bonds, $52 million of senior unsecured notes and $34 million of mortgage notes and the reduction of our short-term commercial paper outstanding by $251 million.

Our capital investment plans for the remainder of 2009 will require additional funding from the capital markets.

Off-balance Sheet Arrangements

Under a limited set of circumstances, we enter into off-balance sheet arrangements 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:

	March 31, 2009	December 31, 2008
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 578	$ 650
Rockport Plant Unit 2 Future Minimum Lease Payments	2,070	2,070
Railcars Maximum Potential Loss From Lease Agreement	25	25

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 2008 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2008 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 2008 Annual Report. The 2008 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 2008 Annual Report, but may have a material impact on our future net income, cash flows and financial condition.

Ohio Electric Security Plan Filings

In March 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs which will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the fuel adjustment clause (FAC). The ordered increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. After final PUCO review and approval of conforming rate schedules, CSPCo and OPCo implemented rates for the April 2009 billing cycle. CSPCo and OPCo will collect the 2009 annualized revenue increase over the remainder of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. As of March 31, 2009, the FAC deferral balances were $17 million and $66 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales. In addition, the ESP order provided for both the FAC deferral credits and the off-system sales margins to be excluded from the methodology for the Significantly Excessive Earnings Test (SEET). The SEET is discussed below.

Additionally, the order addressed several other items, including:

- The approval of new distribution riders, subject to true-up for recovery of costs for enhanced vegetation management programs for CSPCo and OPCo and the proposed gridSMART advanced metering initial program roll out in a portion of CSPCo's service territory. The PUCO proposed that CSPCo mitigate the costs of gridSMART by seeking matching funds under the American Recovery and Reinvestment Act of 2009. As a result, a rider was established to recover 50% or $32 million of the projected $64 million revenue requirement related to gridSMART costs. The PUCO denied the other distribution system reliability programs proposed by CSPCo and OPCo as part of their ESP filings. The PUCO decided that those requests should be examined in the context of a complete distribution base rate case. The order did not require CSPCo and/or OPCo to file a distribution base rate case.

- The approval of CSPCo's and OPCo's request to recover the incremental carrying costs related to environmental investments made from 2001 through 2008 that are not reflected in existing rates. Future recovery during the ESP period of incremental carrying charges on environmental expenditures incurred beginning in 2009 may be requested in annual filings.

- The approval of a $97 million and $55 million increase in CSPCo's and OPCo's Provider of Last Resort charges, respectively, to compensate for the risk of customers changing electric suppliers during the ESP period.

- The requirement that CSPCo's and OPCo's shareholders fund a combined minimum of $15 million in costs over the ESP period for low-income, at-risk customer programs. This funding obligation was recognized as a liability and an unfavorable adjustment to Other Operation and Maintenance expense for the three-month period ending March 31, 2009.

- The deferral of CSPCo's and OPCo's request to recover certain existing regulatory assets, including customer choice implementation and line extension carrying costs as part of the ESPs. The PUCO decided it would be more appropriate to consider this request in the context of CSPCo's and OPCo's next distribution base rate case. These regulatory assets, which were approved by prior PUCO orders, total $58 million for CSPCo and $40 million for OPCo as of March 31, 2009. In addition, CSPCo and OPCo would recover and recognize as income, when collected, $35 million and $26 million, respectively, of related unrecorded equity carrying costs incurred through March 2009.

Finally, consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the SEET that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings as measured by whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that have comparable business and financial risk. If the rate adjustments, in the aggregate, result in significantly excessive earnings in comparison, the PUCO must require that the amount of the excess be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until the second or third quarter of 2010.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP, not to the effective date of tariffs and clarified the tariffs were not retroactive. In March 2009, CSPCo and OPCo implemented the new ESP tariffs effective with the start of the April 2009 billing cycle. In April 2009, CSPCo and OPCo filed a motion requesting rehearing of several issues. In April 2009, several intervenors filed motions requesting rehearing of issues underlying the PUCO's authorized rate increases and one intervenor filed a motion requesting the PUCO to direct CSPCo and OPCo to cease collecting rates under the order. Certain intervenors also filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases.

Management will evaluate whether it will withdraw the ESP applications after a final order, thereby terminating the ESP proceedings. If CSPCo and/or OPCo withdraw the ESP applications, CSPCo and/or OPCo may file a Market Rate Offer (MRO) or another ESP as permitted by the law. The revenues collected and recorded in 2009 under this PUCO order are subject to possible refund through the SEET process. Management is unable, due to the decision of the PUCO to defer guidance on the SEET methodology to a future generic SEET proceeding, to estimate the amount, if any, of a possible refund that could result from the SEET process in 2010.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

I&M maintains property insurance through NEIL with a $1 million deductible. As of March 31, 2009, we recorded $34 million in Prepayments and Other on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursements from NEIL for the cost incurred to date to repair the property damage. 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 for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In the first quarter of 2009, I&M recorded $54 million in revenues, including $9 million in revenues that were deferred at December 31, 2008, related to the accidental outage policy. In order to hold customers harmless, in the first quarter of 2009, I&M applied $20 million of the accidental outage insurance proceeds to reduce fuel underrecoveries reflecting recoverable fuel costs as if Unit 1 were operating. 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.

<u>Texas Restructuring Appeals</u>

Pursuant to PUCT orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 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. This remand could potentially have an adverse effect on TCC's future net income and cash flows if upheld on appeal. The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness which could have a favorable effect on TCC's future net income and cash flows.

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 two major respects. It reversed the District Court's unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated REPs. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earnings based upon the reasons discussed in the "TCC Excess Earnings" section below. The favorable commercial unreasonableness judgment entered by the District Court 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. Review is discretionary and the Texas Supreme Court has not determined if it will grant review. In January 2009, the Texas Supreme Court requested full briefing of the proceedings.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. The appeal brought by TNC of the final true-up order remains pending in state court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in their 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 material adverse effect on future net income, cash flows and possibly financial condition.

New Generation/Purchase Power Agreement

In 2009, AEP 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)				
AEGCo	Dresden	(c)	Ohio	$ 322	$ 189	Gas	Combined-cycle	580	2013
SWEPCo	Stall		Louisiana	385	291	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(d)	Arkansas	1,628(d)	480	Coal	Ultra-supercritical	600(d)	2012
APCo	Mountaineer	(e)	West Virginia	(e)		Coal	IGCC	629	(e)
CSPCo/OPCo	Great Bend	(e)	Ohio	(e)		Coal	IGCC	629	(e)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) 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.
(d) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. See "Turk Plant" section below.
(e) Construction of IGCC plants is subject to regulatory approvals. See "IGCC Plants" section below.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners have appealed the APSC's decision 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 previously estimated $1.522 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. 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 emission costs exceed the restrictions, it could have a material adverse effect 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.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. 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 2009, SWEPCo filed a motion to dismiss the appeal. In March 2009, the motion was granted.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant's permit is heard. Hearings on the air permit appeal are scheduled for June 2009. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers a potential wetlands impact on approximately 2.5 acres at the Turk Plant. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas of the Turk Plant. The impact on the construction schedule and workforce is currently being evaluated by management.

In January and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications 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. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor's Commission on Global Warming issued its final report to the governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build and operate 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 costs incurred plus related shutdown costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of March 31, 2009, SWEPCo has capitalized approximately $480 million of expenditures (including AFUDC) and has contractual construction commitments for an additional $655 million. As of March 31, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $100 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.

IGCC Plants

The construction of the West Virginia and Ohio IGCC plants are pending regulatory approvals. In April 2008, the Virginia SCC issued an order denying 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. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. 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 March 2009, APCo deferred for future recovery preconstruction IGCC costs of $20 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, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. However, 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 pre-construction 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.

PSO Purchase Power Agreement

PSO and Exelon Generation Company LLC, a subsidiary of Exelon Corporation, executed a long-term purchase power agreement (PPA) for which an application seeking its approval is expected to be filed with the OCC. The PPA is for the purchase of up to 520 MW of electric generation from the 795 MW natural gas-fired Green Country Generating Station, located in Jenks, Oklahoma. The agreement is the result of PSO's 2008 Request for Proposals following a December 2007 OCC order that found PSO had a need for new baseload generation by 2012.

Litigation

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss 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 2008 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 and cash flows.

Environmental Litigation

New Source Review (NSR) Litigation: The Federal EPA, a number of states and certain special interest groups filed complaints alleging that CSPCo, 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.

Litigation continues against Beckjord, a plant jointly-owned by CSPCo, Duke and DP&L, which Duke operates. A jury trial returned a verdict of no liability at the Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. We are unable to predict the outcome of this case. We believe we can recover any capital and operating costs of additional pollution control equipment that may be required through future regulated rates or market prices for electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future net income and cash flows.

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

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. We are also involved in the development of possible future requirements to reduce CO_2 and other greenhouse gases (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 2008 Annual Report.

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 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 sought further review and filed for relief from the schedules included in our permits.

In April 2009, the U.S. Supreme Court issued a decision that allows the Federal EPA the discretion to rely on cost-benefit analysis in setting national performance standards and in providing for cost-benefit variances from those standards as part of the regulations. We cannot predict if or how the Federal EPA will apply this decision to any revision of the regulations or what effect it may have on similar requirements adopted by the states.

Potential Regulation of CO_2 and Other GHG Emissions

As discussed in the 2008 Annual Report, CO_2 and other GHG are alleged to contribute to climate change. In April 2009, the Federal EPA issued a proposed endangerment finding under the CAA regarding GHG emissions from motor vehicles. The proposed endangerment finding is subject to public comment. This finding could lead to regulation of CO_2 and other gases under existing laws. Congress continues to discuss new legislation related to the control of these emissions. Some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including us. Because of these adverse consequences, management believes that these more extreme policies will not ultimately be adopted. Even if reasonable CO_2 and other GHG emission standards are imposed, they will still require us to make material expenditures. Management believes that costs of complying with new CO_2 and other GHG emission standards will be treated like all other reasonable costs of serving customers, and should be recoverable from customers as costs of doing business including capital investments with a return on investment.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2008 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

The FASB issued SFAS 141R (revised "Business Combinations" 2007) improving financial reporting about business combinations and their effects. SFAS 141R can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments. We adopted SFAS 141R effective January 1, 2009. We will apply it to any future business combinations.

The FASB issued SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. We adopted SFAS 160 effective January 1, 2009 and retrospectively applied the standard to prior periods. See Note 2.

The FASB issued SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161), enhancing disclosure requirements for derivative instruments and hedging activities. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard increased our disclosure requirements related to derivative instruments and hedging activities. We adopted SFAS 161 effective January 1, 2009.

The FASB ratified EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5) a 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. We adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability.

The FASB ratified EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6), a consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. We prospectively adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements.

We adopted FSP EITF 03-6-1 "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" (EITF 03-6-1) effective January 1, 2009. The rule addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method. The adoption of this standard had an immaterial impact on our financial statements.

The FASB issued FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. We adopted the rule effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

The FASB issued 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). 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. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals. We adopted SFAS 157-2 effective January 1, 2009. We will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. We did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first quarter of 2009.

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 settle and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, coal, natural gas and emission allowances and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our 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 balance sheet as of March 31, 2009 and the reasons for changes in our total MTM value included on our balance sheet as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet March 31, 2009 (in millions)

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	Cash Flow Hedge Contracts	Collateral Deposits	Total
Current Assets	$ 256	$ 27	$ 4	$ 287	$ 40	$ (34)	$ 293
Noncurrent Assets	228	221	7	456	1	(40)	417
Total Assets	484	248	11	743	41	(74)	710
Current Liabilities	(153)	(23)	(9)	(185)	(31)	37	(179)
Noncurrent Liabilities	(155)	(85)	(10)	(250)	(4)	80	(174)
Total Liabilities	(308)	(108)	(19)	(435)	(35)	117	(353)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 176	$ 140	$ (8)	$ 308	$ 6	$ 43	$ 357

MTM Risk Management Contract Net Assets (Liabilities) Three Months Ended March 31, 2009 (in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2008	$ 175	$ 104	$ (7)	$ 272
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(27)	(3)	1	(29)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2	51	-	53
Net Option Premiums Paid (Received) for Unexercised or Unexpired Option Contracts Entered During the Period	-	-	-	-
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	7	(12)	(2)	(7)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	19	-	-	19
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2009	$ 176	$ 140	$ (8)	308
Cash Flow Hedge Contracts				6
Collateral Deposits				43
Ending Net Risk Management Assets at March 31, 2009				$ 357

(a) Reflects fair value on long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

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 March 31, 2009
(in millions)

	Remainder 2009	2010	2011	2012	2013	After 2013 (f)	Total
Utility Operations							
Level 1 (a)	$ (6)	$ -	$ -	$ -	$ -	$ -	$ (6)
Level 2 (b)	62	34	17	(1)	-	-	112
Level 3 (c)	16	8	5	5	1	-	35
Total	72	42	22	4	1	-	141
Generation and Marketing							
Level 1 (a)	(8)	-	-	-	-	-	(8)
Level 2 (b)	7	15	16	16	18	25	97
Level 3 (c)	1	1	2	1	3	43	51
Total	-	16	18	17	21	68	140
All Other							
Level 1 (a)	-	(1)	-	-	-	-	(1)
Level 2 (b)	(4)	(5)	2	-	-	-	(7)
Level 3 (c)	-	-	-	-	-	-	-
Total	(4)	(6)	2	-	-	-	(8)
Total							
Level 1 (a)	(14)	(1)	-	-	-	-	(15)
Level 2 (b)	65	44	35	15	18	25	202
Level 3 (c) (d)	17	9	7	6	4	43	86
Total	68	52	42	21	22	68	273
Dedesignated Risk Management Contracts (e)	10	14	6	5	-	-	35
Total MTM Risk Management Contract Net Assets (Liabilities)	$ 78	$ 66	$ 48	$ 26	$ 22	$ 68	$ 308

(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 contracts.

(f) There is mark-to-market value of $68 million in individual periods beyond 2014. $46 million of this mark-to-market value is in periods 2014-2018, $15 million is in periods 2019-2023 and $7 million is in periods 2024-2028.

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 March 31, 2009, our credit exposure net of collateral to sub investment grade counterparties was approximately 10.6%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of March 31, 2009, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 670	$ 89	$ 581	1	$ 133
Split Rating	8	1	7	2	7
Noninvestment Grade	14	-	14	1	13
No External Ratings:					
Internal Investment Grade	166	16	150	4	87
Internal Noninvestment Grade	83	10	73	2	55
Total as of March 31, 2009	$ 941	$ 116	$ 825	10	$ 295
Total as of December 31, 2008	$ 793	$ 29	$ 764	9	$ 284

See Note 7 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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 March 31, 2009 a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

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

VaR Model

Three Months Ended March 31, 2009 (in millions)				Twelve Months Ended December 31, 2008 (in millions)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$1	$1	$1	$-	$-	$3	$1	$-

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

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

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 $19 million. This amount includes the estimated impact of the April 2009 issuance of AEP common stock.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in millions, except per-share and share amounts)
(Unaudited)

REVENUES	2009	2008
Utility Operations	$ 3,267	$ 3,010
Other	191	457
TOTAL	3,458	3,467
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	929	980
Purchased Electricity for Resale	295	263
Other Operation and Maintenance	914	878
Gain on Disposition of Assets, Net	(9)	(3)
Asset Impairments and Other Related Charges	-	(255)
Depreciation and Amortization	382	363
Taxes Other Than Income Taxes	197	198
TOTAL	2,708	2,424
OPERATING INCOME	750	1,043
Other Income (Expense):		
Interest and Investment Income	5	16
Carrying Costs Income	9	17
Allowance for Equity Funds Used During Construction	16	10
Interest Expense	(238)	(219)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	542	867
Income Tax Expense	179	293
Equity Earnings of Unconsolidated Subsidiaries	-	2
NET INCOME	363	576
Less: Net Income Attributable to Noncontrolling Interests	2	2
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	361	574
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 360	$ 573
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	406,826,606	400,797,993
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 0.89	$ 1.43
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	407,381,954	402,072,098
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 0.89	$ 1.43
CASH DIVIDENDS PAID PER SHARE	$ 0.41	$ 0.41

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 710	$ 411
Other Temporary Investments	215	327
Accounts Receivable:		
Customers	555	569
Accrued Unbilled Revenues	378	449
Miscellaneous	70	90
Allowance for Uncollectible Accounts	(41)	(42)
Total Accounts Receivable	962	1,066
Fuel	740	634
Materials and Supplies	550	539
Risk Management Assets	293	256
Regulatory Asset for Under-Recovered Fuel Costs	320	284
Margin Deposits	125	86
Prepayments and Other	203	172
TOTAL	4,118	3,775
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	22,300	21,242
Transmission	7,955	7,938
Distribution	12,990	12,816
Other (including coal mining and nuclear fuel)	3,772	3,741
Construction Work in Progress	3,147	3,973
Total	50,164	49,710
Accumulated Depreciation and Amortization	16,913	16,723
TOTAL - NET	33,251	32,987
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,837	3,783
Securitized Transition Assets	2,011	2,040
Spent Nuclear Fuel and Decommissioning Trusts	1,207	1,260
Goodwill	76	76
Long-term Risk Management Assets	417	355
Deferred Charges and Other	948	879
TOTAL	8,496	8,393
TOTAL ASSETS	$ 45,865	$ 45,155

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2009	2008
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,126	$ 1,297
Short-term Debt	1,976	1,976
Long-term Debt Due Within One Year	939	447
Risk Management Liabilities	179	134
Customer Deposits	266	254
Accrued Taxes	614	634
Accrued Interest	226	270
Regulatory Liability for Over-Recovered Fuel Costs	155	66
Other	930	1,219
TOTAL	6,411	6,297
NONCURRENT LIABILITIES		
Long-term Debt	15,904	15,536
Long-term Risk Management Liabilities	174	170
Deferred Income Taxes	5,255	5,128
Regulatory Liabilities and Deferred Investment Tax Credits	2,652	2,789
Asset Retirement Obligations	1,166	1,154
Employee Benefits and Pension Obligations	2,162	2,184
Deferred Credits and Other	1,122	1,126
TOTAL	28,435	28,087
TOTAL LIABILITIES	34,846	34,384
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock Par Value $6.50:		
(20,249,992 shares were held in treasury at March 31, 2009 and December 31, 2008)	2,782	2,771
Paid-in Capital	4,564	4,527
Retained Earnings	4,040	3,847
Accumulated Other Comprehensive Income (Loss)	(446)	(452)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	10,940	10,693
Noncontrolling Interests	18	17
TOTAL EQUITY	10,958	10,710
TOTAL LIABILITIES AND EQUITY	$ 45,865	$ 45,155

	2009	2008
Shares Authorized	600,000,000	600,000,000
Shares Issued	428,010,854	426,321,248

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2009 and 2008
(in millions)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 363	$ 576
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	382	363
Deferred Income Taxes	217	111
Carrying Costs Income	(9)	(17)
Allowance for Equity Funds Used During Construction	(16)	(10)
Mark-to-Market of Risk Management Contracts	(46)	(26)
Amortization of Nuclear Fuel	13	22
Deferred Property Taxes	(64)	(64)
Fuel Over/Under-Recovery, Net	(95)	(57)
Gain on Sales of Assets	(9)	(3)
Change in Other Noncurrent Assets	32	(119)
Change in Other Noncurrent Liabilities	18	(71)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	102	61
Fuel, Materials and Supplies	(118)	20
Margin Deposits	(39)	(4)
Accounts Payable	3	(7)
Customer Deposits	12	6
Accrued Taxes, Net	(57)	149
Accrued Interest	(44)	(44)
Other Current Assets	(7)	(21)
Other Current Liabilities	(321)	(234)
Net Cash Flows from Operating Activities	317	631
INVESTING ACTIVITIES		
Construction Expenditures	(897)	(778)
Change in Other Temporary Investments, Net	111	(26)
Purchases of Investment Securities	(179)	(491)
Sales of Investment Securities	158	500
Acquisition of Nuclear Fuel	(76)	(98)
Proceeds from Sales of Assets	172	18
Other	(16)	(19)
Net Cash Flows Used for Investing Activities	(727)	(894)
FINANCING ACTIVITIES		
Issuance of Common Stock	48	45
Change in Short-term Debt, Net	-	(251)
Issuance of Long-term Debt	947	916
Retirement of Long-term Debt	(93)	(289)
Principal Payments for Capital Lease Obligations	(23)	(23)
Dividends Paid on Common Stock	(169)	(167)
Dividends Paid on Cumulative Preferred Stock	(1)	(1)
Other	-	10
Net Cash Flows from Financing Activities	709	240
Net Increase (Decrease) in Cash and Cash Equivalents	299	(23)
Cash and Cash Equivalents at Beginning of Period	411	178
Cash and Cash Equivalents at End of Period	$ 710	$ 155
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 314	$ 252
Net Cash Paid for Income Taxes	2	36
Noncash Acquisitions Under Capital Leases	6	19
Noncash Acquisition of Land/Mineral Rights	-	42
Construction Expenditures Included in Accounts Payable at March 31,	294	284
Acquisition of Nuclear Fuel Included in Accounts Payable at March 31,	17	-

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2009 and 2008
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
DECEMBER 31, 2007	422	$ 2,743	$ 4,352	$ 3,138	$ (154)	$ 18	$ 10,097
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	1	7	38				45
Common Stock Dividends				(165)		(2)	(167)
Preferred Stock Dividends				(1)			(1)
Other			1			2	3
TOTAL							9,966
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $17					(30)		(30)
Securities Available for Sale, Net of Tax of $3					(6)		(6)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $2					3		3
NET INCOME				574		2	576
TOTAL COMPREHENSIVE INCOME							543
MARCH 31, 2008	423	$ 2,750	$ 4,391	$ 3,535	$ (187)	$ 20	$ 10,509
DECEMBER 31, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 17	$ 10,710
Issuance of Common Stock	2	11	37				48
Common Stock Dividends				(167)		(2)	(169)
Preferred Stock Dividends				(1)			(1)
Other						1	1
TOTAL							10,589
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $1					3		3
Securities Available for Sale, Net of Tax of $1					(2)		(2)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3					5		5
NET INCOME				361		2	363
TOTAL COMPREHENSIVE INCOME							369
MARCH 31, 2009	428	$ 2,782	$ 4,564	$ 4,040	$ (446)	$ 18	$ 10,958

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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 months ended March 31, 2009 is not necessarily indicative of results that may be expected for the year ending December 31, 2009. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2008 consolidated financial statements and notes thereto, which are included in our Annual Report on Form 10-K for the year ended December 31, 2008 as filed with the SEC on February 27, 2009.

Earnings Per Share (EPS)

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

	Three Months Ended March 31, 2009		Three Months Ended March 31, 2008	
	(in millions, except per share data)	$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 360		$ 573	
Weighted Average Number of Basic Shares Outstanding	406.8	$ 0.89	400.8	$ 1.43
Weighted Average Dilutive Effect of:				
Performance Share Units	0.5	-	0.9	-
Stock Options	-	-	0.2	-
Restricted Stock Units	0.1	-	0.1	-
Restricted Shares	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	407.4	$ 0.89	402.1	$ 1.43

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

Options to purchase 618,916 and 146,900 shares of common stock were outstanding at March 31, 2009 and 2008, 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.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments have been consistently applied and that there are no other reasonable judgments or assumptions that would have resulted in a different conclusion.

We are the primary beneficiary of Sabine, DHLC, JMG and a protected cell of EIS. We hold a variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series). In addition, we have not provided financial or other support to any VIE that was not previously contractually required.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo has guaranteed the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee which is included in Fuel and Other Consumables Used for Electric Generation on our Condensed Consolidated Statements of Income. Based on these facts, management has concluded SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended March 31, 2009 and 2008 were $35 million and $20 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Condensed Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC's debt. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate DHLC. SWEPCo's total billings from DHLC for the three months ended March 31, 2009 and 2008 were $11 million and $12 million, respectively. These billings are included in Fuel and Other Consumables Used for Electric Generation on our Condensed Consolidated Statements of Income. See the tables below for the classification of DHLC assets and liabilities on our Condensed Consolidated Balance Sheets.

OPCo has a lease agreement with JMG to finance OPCo's Flue Gas Desulfurization (FGD) system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments are the only form of repayment associated with JMG's debt obligations even though OPCo does not guarantee JMG's debt. The creditors of JMG have no recourse to any AEP entity other than OPCo for the lease payment. OPCo does not have any ownership interest in JMG. Based on the structure of the entity, management has concluded OPCo is the primary beneficiary and is required to consolidate JMG. OPCo's total billings from JMG for the three months ended March 31, 2009 and 2008 were $17 million and $12 million, respectively. See the tables below for the classification of JMG's assets and liabilities on our Condensed Consolidated Balance Sheets.

EIS is a captive insurance company with multiple protected cells in which our subsidiaries participate in one protected cell for approximately ten lines of insurance. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP system is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on the structure of the protected cell, management has concluded that we are the primary beneficiary and that we are required to consolidate the protected cell. Our insurance premium payments to EIS for the three months ended March 31, 2009 and 2008 were $17 million in both periods. See the tables below for the classification of EIS's assets and liabilities on our Condensed Consolidated Balance Sheets.

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

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

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	EIS
ASSETS				
Current Assets	$ 34	$ 18	$ 13	$ 118
Net Property, Plant and Equipment	122	32	417	-
Other Noncurrent Assets	30	11	1	1
Total Assets	$ 186	$ 61	$ 431	$ 119
LIABILITIES AND EQUITY				
Current Liabilities	$ 34	$ 12	$ 156	$ 41
Noncurrent Liabilities	152	45	257	64
Equity	-	4	18	14
Total Liabilities and Equity	$ 186	$ 61	$ 431	$ 119

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

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

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the “Ohio Series,” the “West Virginia Series (PATH-WV),” both owned equally by AYE and us and the “Allegheny Series” which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The “Ohio Series” does not include the same provisions that make PATH-WV a VIE. The other series are not considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other on our Condensed Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE’s subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series will be consistent with other regulated utilities and the entities are designed to maintain this financing structure. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. Currently the entity has no debt financing. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	March 31, 2009		December 31, 2008	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 4	$ 4	$ 4	$ 4
Retained Earnings	1	1	2	2
Total Investment in PATH-WV	$ 5	$ 5	$ 6	$ 6

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We recognize the revenues on our Condensed Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

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

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on our Condensed Consolidated Statements of Income.

CSPCo and OPCo Revised Depreciation Rates

Effective January 1, 2009, we revised book depreciation rates for CSPCo and OPCo generating plants consistent with a recently completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain OPCo generating facilities. The impact of the change in depreciation rates was an increase in OPCo's depreciation expense of $17 million and a decrease in CSPCo's depreciation expense of $4 million when comparing the three months ended March 31, 2009 and 2008.

Acquisition – Oxbow Mine Lignite (Utility Operations segment)

In April 2009, SWEPCo and its wholly-owned lignite mining subsidiary, Dolet Hills Mining Company, LLC (DHLC), agreed to purchase 50% of the Oxbow Mine lignite reserves and 100% of all associated mining equipment and assets from The North American Coal Corporation and its affiliates, Red River Mining Company and Oxbow Property Company, LLC for $42 million. Cleco Power LLC (Cleco) will acquire the remaining 50% of the lignite reserves. Consummation of the transaction is subject to regulatory approval by the LPSC and the APSC and the transfer of other regulatory instruments. If approved, DHLC will acquire and own the Oxbow Mine mining equipment and related assets and it will operate the Oxbow Mine. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for SWEPCo's and Cleco's jointly-owned Dolet Hills Generating Station.

Supplementary Information

Related Party Transactions	Three Months Ended March 31, 2009	2008
	(in millions)	
AEP Consolidated Revenues – Utility Operations:		
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% owned) (a)	$ -	$ (13)
AEP Consolidated Revenues – Other:		
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	9	9
AEP Consolidated Expenses – Purchased Electricity for Resale:		
Ohio Valley Electric Corporation (43.47% Owned)	70	63

(a) In 2006, the AEP Power Pool began purchasing power from OVEC as part of risk management activities. The agreement expired in May 2008 and subsequently ended in December 2008.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements issued or implemented in 2009 and standards issued but not implemented that we have determined relate to our operations.

Pronouncements Adopted During the First Quarter of 2009

The following standards were effective during the first quarter of 2009. Consequently, the financial statements and footnotes reflect their impact.

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 established 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. The standard 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 can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

We adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. We will apply it to any future business combinations.

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

We adopted SFAS 160 effective January 1, 2009 and retrospectively applied the standard to prior periods. The retrospective application of this standard:

- Reclassifies Minority Interest Expense of $1 million and Interest Expense of $1 million for the three months ended March 31, 2008 as Net Income Attributable to Noncontrolling Interest below Net Income in the presentation of Earnings Attributable to AEP Common Shareholders in our Condensed Consolidated Statements of Income.
- Repositions Preferred Stock Dividend Requirements of Subsidiaries of $1 million for the three months ended March 31, 2008 below Net Income in the presentation of Earnings Attributable to AEP Common Shareholders in our Condensed Consolidated Statements of Income.
- Reclassifies minority interest of $17 million as of December 31, 2008 previously included in Deferred Credits and Other and Total Liabilities as Noncontrolling Interest in Total Equity on our Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interest in the Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $2 million for the three months ended March 31, 2008 from Operating Activities to Financing Activities in our Condensed Consolidated Statements of Cash Flows.

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 an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

We adopted SFAS 161 effective January 1, 2009. This standard increased our disclosures related to derivative instruments and hedging activities. See "Derivatives and Hedging " section of Note 7 for further information.

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 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. 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.

We adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

We adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements. It was applied prospectively.

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 addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method described in SFAS 128 "Earnings per Share."

We adopted EITF 03-6-1 effective January 1, 2009. The adoption of this standard had an immaterial impact on our financial statements.

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. 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.

We adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2)

In February 2008, the FASB issued 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). 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. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

We adopted SFAS 157-2 effective January 1, 2009. We will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. We did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first quarter of 2009.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

This standard is effective for interim periods ending after June 15, 2009. Management expects this standard to increase the disclosure requirements related to financial instruments. We will adopt the standard effective second quarter of 2009.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

This standard is effective for interim periods ending after June 15, 2009. Management does not expect a material impact as a result of the new OTTI evaluation method for debt securities, but expects this standard to increase the disclosure requirements related to financial instruments. We will adopt the standard effective second quarter of 2009.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to our benefit plans. We will adopt the standard effective for the 2009 Annual Report.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

This standard is effective for interim and annual periods ending after June 15, 2009. Management expects this standard to have no impact on our financial statement but will increase our disclosure requirements. We will adopt the standard effective second quarter of 2009.

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, insurance, hedge accounting, consolidation policy, discontinued operations, 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.

3. RATE MATTERS

As discussed in the 2008 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2008 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 2009 and updates the 2008 Annual Report.

Ohio Rate Matters

Ohio Electric Security Plan Filings

In July 2008, as required by the 2008 amendments to the Ohio restructuring legislation, CSPCo and OPCo filed ESPs with the PUCO to establish standard service offer rates. CSPCo and OPCo did not file an optional Market Rate Offer (MRO). CSPCo's and OPCo's ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a fuel adjustment clause (FAC) that includes fuel costs, purchased power costs, consumables such as urea, gains and losses on sales of emission allowances and most other variable production costs. FAC costs were proposed to be phased into customer bills over the three-year period from 2009 through 2011 with unrecovered FAC costs to be recorded as a FAC phase-in regulatory asset. The phase-in regulatory asset deferral along with a deferred weighted average cost of capital carrying cost was proposed to be recovered over seven years from 2012 through 2018.

In March 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the FAC. The ordered increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. After final PUCO review and approval of conforming rate schedules, CSPCo and OPCo implemented rates for the April 2009 billing cycle. CSPCo and OPCo will collect the 2009 annualized revenue increase over the remainder of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. As of March 31, 2009, the FAC deferral balances were $17 million and $66 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales. In addition, the ESP order provided for both the FAC deferral credits and the off-system sales margins to be excluded from the methodology for the Significantly Excessive Earnings Test (SEET). The SEET is discussed below.

Additionally, the order addressed several other items, including:

- The approval of new distribution riders, subject to true-up for recovery of costs for enhanced vegetation management programs, for CSPCo and OPCo and the proposed gridSMART advanced metering initial program roll out in a portion of CSPCo's service territory. The PUCO proposed that CSPCo mitigate the costs of gridSMART by seeking matching funds under the American Recovery and Reinvestment Act of 2009. As a result, a rider was established to recover 50% or $32 million of the projected $64 million revenue requirement related to gridSMART costs. The PUCO denied the other distribution system reliability programs proposed by CSPCo and OPCo as part of their ESP filings. The PUCO decided that those requests should be examined in the context of a complete distribution base rate case. The order did not require CSPCo and/or OPCo to file a distribution base rate case.

- The approval of CSPCo's and OPCo's request to recover the incremental carrying costs related to environmental investments made from 2001 through 2008 that are not reflected in existing rates. Future recovery during the ESP period of incremental carrying charges on environmental expenditures incurred beginning in 2009 may be requested in annual filings.

- The approval of a $97 million and $55 million increase in CSPCo's and OPCo's Provider of Last Resort charges, respectively, to compensate for the risk of customers changing electric suppliers during the ESP period.

- The requirement that CSPCo's and OPCo's shareholders fund a combined minimum of $15 million in costs over the ESP period for low-income, at-risk customer programs. This funding obligation was recognized as a liability and an unfavorable adjustment to Other Operation and Maintenance expense for the three-month period ending March 31, 2009.

- The deferral of CSPCo's and OPCo's request to recover certain existing regulatory assets, including customer choice implementation and line extension carrying costs as part of the ESPs. The PUCO decided it would be more appropriate to consider this request in the context of CSPCo's and OPCo's next distribution base rate case. These regulatory assets, which were approved by prior PUCO orders, total $58 million for CSPCo and $40 million for OPCo as of March 31, 2009. In addition, CSPCo and OPCo would recover and recognize as income, when collected, $35 million and $26 million, respectively, of related unrecorded equity carrying costs incurred through March 2009.

Finally, consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the SEET that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings as measured by whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that have comparable business and financial risk. If the rate adjustments, in the aggregate, result in significantly excessive earnings in comparison, the PUCO must require that the amount of the excess be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until the second or third quarter of 2010.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP, not to the effective date of tariffs and clarified the tariffs were not retroactive. In March 2009, CSPCo and OPCo implemented the new ESP tariffs effective with the start of the April 2009 billing cycle. In April 2009, CSPCo and OPCo filed a motion requesting rehearing of several issues. In April 2009, several intervenors filed motions requesting rehearing of issues underlying the PUCO's authorized rate increases and one intervenor filed a motion requesting the PUCO to direct CSPCo and OPCo to cease collecting rates under the order. Certain intervenors also filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases.

Management will evaluate whether it will withdraw the ESP applications after a final order, thereby terminating the ESP proceedings. If CSPCo and/or OPCo withdraw the ESP applications, CSPCo and/or OPCo may file an MRO or another ESP as permitted by the law. The revenues collected and recorded in 2009 under this PUCO order are subject to possible refund through the SEET process. Management is unable, due to the decision of the PUCO to defer guidance on the SEET methodology to a future generic SEET proceeding, to estimate the amount, if any, of a possible refund that could result from the SEET process in 2010.

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. In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover 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 pre-construction cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest.

In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest. In October 2008, 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.

In January 2009, a PUCO Attorney Examiner issued an order that CSPCo and OPCo file a detailed statement outlining the status of the construction of the IGCC plant, including whether CSPCo and OPCo are engaged in a continuous course of construction on the IGCC plant. In February 2009, CSPCo and OPCo filed a statement that CSPCo and OPCo have not commenced construction of the IGCC plant and believe there exist real statutory barriers to the construction of any new base load generation in Ohio, including IGCC plants. The statement also indicated that while construction on the IGCC plant might not begin by June 2011, changes in circumstances could result in the commencement of construction on a continuous course by that time.

Management continues to pursue the ultimate construction of the IGCC plant. However, CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists. 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. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what, if any effect, the litigation will have on future net income and cash flows.

Ormet

In December 2008, CSPCo, OPCo and Ormet, a large aluminum company with a load of 520 MW, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. The arrangement would be effective January 1, 2009 and remain in effect and expire upon the effective date of CSPCo's and OPCo's new ESP rates and the effective date of a new arrangement between Ormet and CSPCo/OPCo as approved by the PUCO. Under the interim arrangement, Ormet would pay the then-current applicable generation tariff rates and riders. CSPCo and OPCo sought to defer as a regulatory asset beginning in 2009 the difference between the PUCO approved 2008 market price of $53.03 per MWH and the applicable generation tariff rates and riders. CSPCo and OPCo proposed to recover the deferral through the fuel adjustment clause mechanism they proposed in the ESP proceeding. In January 2009, the PUCO approved the application as an interim arrangement. In February 2009, an intervenor filed an application for rehearing of the PUCO's interim arrangement approval. In March 2009, the PUCO granted that application for further consideration of the matters specified in the rehearing application.

In February 2009, as amended in April 2009, Ormet filed an application with the PUCO for approval of a proposed Ormet power contract for 2009 through 2018. Ormet proposed to pay varying amounts based on certain conditions, including the price of aluminum and the level of production. The difference between the amounts paid by Ormet and the otherwise applicable PUCO ESP tariff rate would be either collected from or refunded to CSPCo's and OPCo's retail customers.

In March 2009, the PUCO issued an order in the ESP filings which included approval of a FAC for the ESP period. The approval of an ESP FAC, together with the January 2009 PUCO approval of the Ormet interim arrangement, provided the basis to record regulatory assets of $10 million and $9 million for CSPCo and OPCo, respectively, for the differential in the approved market price of $53.03 versus the rate paid by Ormet during the first quarter of 2009. These amounts are included in CSPCo's and OPCo's FAC phase-in deferral balance of $17 million and $66 million, respectively. See "Ohio Electric Security Plan Filings" section above.

The pricing and deferral authority under the PUCO's January 2009 approval of the interim arrangement will continue until the 2009-2018 power contract becomes effective. Management cannot predict when or if the PUCO will approve the new power contract.

Hurricane Ike

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. Under the RSP, which was effective in 2008, CSPCo and OPCo could 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 expected recovery of the storm restoration costs. In December 2008, CSPCo and OPCo filed with the PUCO a request to establish the regulatory assets under the terms of the RSP, plus accrue carrying costs on the unrecovered balance using CSPCo's and OPCo's weighted average cost of capital carrying charge rates. In December 2008, the PUCO subsequently approved the establishment of the regulatory assets but authorized CSPCo and OPCo to record a long-term debt only carrying cost on the regulatory asset. In its order approving the deferrals, the PUCO stated that the mechanism for recovery would be determined in CSPCo's and OPCo's next distribution rate filing.

In December 2008, the Consumers for Reliable Electricity in Ohio filed a request with the PUCO asking for an investigation into the service reliability of Ohio's investor-owned electric utilities, including CSPCo and OPCo. The investigation request included the widespread outages caused by the September 2008 wind storm. CSPCo and OPCo filed a response asking the PUCO to deny the request.

As a result of the past favorable treatment of storm restoration costs under the RSP and the RSP recovery provisions, which were in effect when the storm occurred and the filings made, management believes the recovery of the regulatory assets is probable. However, if these regulatory assets are not recovered, it would have an adverse effect on future net income and cash flows.

<u>Texas Rate Matters</u>

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 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 were:

- 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. This remand could potentially have an adverse effect on TCC's future net income and cash flows if upheld on appeal. The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness which could have a favorable effect on TCC's future net income and cash flows.

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 two major respects. It reversed the District Court's unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated REPs. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earnings based upon the reasons discussed in the "TCC Excess Earnings" section below. The favorable commercial unreasonableness judgment entered by the District Court 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. Review is discretionary and the Texas Supreme Court has not determined if it will grant review. In January 2009, the Texas Supreme Court requested full briefing of the proceedings.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. The appeal brought by TNC of the final true-up order remains pending in state court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in their 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 material adverse effect on future net income, cash flows and possibly financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

TCC's appeal remains 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. Subsequent to the PUCT's ordered reduction to TCC's securitized stranded costs by certain tax benefits, the PUCT, reacting to possible IRS normalization violations, allowed TCC to defer $103 million of ordered CTC refunds for other true-up items to negate the securitization reduction. Of the $103 million, $61 million relates to the present value of certain tax benefits applied to reduce the securitization stranded generating assets and $42 million for related carrying costs. The deferral of the CTC refunds is pending resolution on whether the PUCT's securitization refund is an IRS normalization violation.

Evidence supporting a possible IRS normalization violation includes a March 2008 IRS issuance of final regulations addressing the normalization requirements for the treatment of Accumulated Deferred Investment Tax Credit (ADITC) and Excess Deferred Federal Income Tax (EDFIT) in a stranded cost determination. Consistent with a Private Letter Ruling TCC received in 2006, the final regulations clearly state that TCC will sustain a normalization violation if the PUCT orders TCC to flow the tax benefits to customers as part of the stranded cost true-up. TCC notified the PUCT that the final regulations were issued. The PUCT made a request to the Texas Court of Appeals for the matter to be remanded back to the PUCT for further action. 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 these amounts. This will have a favorable effect on future net income and cash flows as TCC will be free to amortize the deferred ADITC and EDFIT tax benefits to 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 for refunds of these amounts. If accrued, management estimates interest expense would have been approximately $6 million higher for the period July 2008 through March 2009 based on a CTC interest rate of 7.5% with $4 million relating to 2008.

If the PUCT orders TCC to return the tax benefits to customers, thereby causing a violation of the IRS normalization regulations, the violation could result in TCC's repayment to the IRS, under the normalization rules, of ADITC on all property, including transmission and distribution property. This amount approximates $103 million as of March 31, 2009. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay 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 favorably 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 to the REPs in lieu of reducing stranded cost recoveries from REPs 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 excess earnings refunds made 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 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 would have an adverse effect on future net income and cash flows.

Texas Restructuring – SPP

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In April 2009, the Texas Senate passed a bill related to SWEPCo's SPP area of Texas that requires cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all retail customer classes. The bill is expected to be reviewed by the Texas House of Representatives which, if passed, would be sent to the governor of Texas for approval. If the bill is signed, management may be required to re-apply SFAS 71 for the generation portion of SWEPCo's Texas jurisdiction. The initial reapplication of SFAS 71 regulatory accounting would likely result in an extraordinary loss.

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 $23 million and $2 million in incremental 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 annually with authority to continue the collection until the catastrophe reserve reaches $13 million. Any incremental storm-related maintenance costs can be charged against the catastrophe reserve if the total incremental 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. Therefore, TCC established a net regulatory asset for $23 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 to both recover the regulatory asset and adequately fund a reserve for future storms in a reasonable time period.

2008 Interim Transmission Rates

In March 2008, TCC and TNC filed applications with the PUCT for an interim update of wholesale-transmission rates. The PUCT issued an order in May 2008 that provided for increased interim transmission rates for TCC and TNC, subject to review during the next TCC and TNC base rate case. This review could result in a refund if the PUCT finds that TCC and TNC have not prudently incurred the transmission investment. The FERC approved the new interim transmission rates in May 2008 which increased annual transmission revenues by $9 million and $4 million for TCC and TNC, respectively. TCC and TNC have not recorded any provision for refund regarding the interim transmission rates because management believes these new rates are reasonable and necessary to recover costs associated with new transmission plant. Management cannot predict the outcome of future proceedings related to the interim transmission rates. A refund of the interim transmission rates would have an adverse impact on net income and cash flows.

2009 Interim Transmission Rates

In February 2009, TCC and TNC filed applications with the PUCT for an interim update of wholesale-transmission rates. The proposed new interim transmission rates are estimated to increase annual transmission revenues by $8 million and $9 million for TCC and TNC, respectively. In April 2009, the PUCT staff recommended the applications be approved as filed. A decision is expected from the PUCT during the second quarter of 2009 with rates increasing shortly thereafter upon the FERC’s concurrence. Management cannot predict the outcome of the interim transmission rates proceeding.

Advanced Metering System

In 2007, the governor of Texas signed legislation directing the PUCT to establish a surcharge for electric utilities relating to advanced meters. In April 2009, TCC and TNC filed their Advanced Metering System (AMS) with the PUCT proposing to invest approximately $223 million and $61 million, respectively, to be recovered through customer surcharges beginning in October 2009. The TCC and TNC filing is modeled on similar filings by other Texas ERCOT Investor Owned Utilities who have already received PUCT approval for their plans. In the filing TCC and TNC propose to apply customer refunds related to the FERC SIA ruling to reduce the AMS investment and associated customer surcharge. As of March 31, 2009, TCC and TNC has $2.8 million and $0.5 million recorded on their balance sheets related to advanced meters.

Texas Rate Filing

In November 2006, TCC filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rate in Texas. TCC’s revised requested increase in annual base rates was $70 million based on a requested return on common equity of 10.75%.

TCC implemented the rate change in June 2007, subject to refund. In March 2008, the PUCT issued an order approving rates to collect a $20 million base rate increase based on a return on common equity of 9.96% and an additional $20 million increase in revenues related to the expiration of TCC’s merger credits. In addition, depreciation expense was decreased by $7 million and discretionary fee revenues were increased by $3 million. TCC estimates the order will increase TCC’s annual pretax income by $50 million. Various parties appealed the PUCT decision.

In February 2009, the Texas District Court affirmed the PUCT in most respects. However, it also ruled that the PUCT improperly denied TCC an AFUDC return on the prepaid pension asset that the PUCT ruled to be CWIP. In March 2009, various intervenors appealed the Texas District Court decision to the Texas Court of Appeals. Management is unable to predict the outcome of these proceedings. If the appeals are successful, it could have an adverse effect on future net income and cash flows.

ETT

In December 2007, TCC contributed $70 million of transmission facilities to ETT, an AEP joint venture accounted for using the equity method. The PUCT approved ETT's initial rates, a 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 allowed 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 complied with what the court determined was the proper section of the statute. In January 2009, ETT and the PUCT filed appeals to the Texas Court of Appeals. In January and April 2009, TCC sold $60 million and $30 million, respectively, of additional transmission facilities to ETT. As of March 31, 2009, AEP's net investment in ETT was $36 million. Depending upon the ultimate outcome of the appeals and any resulting remands, TCC may be required to reacquire transferred assets and projects under construction by ETT.

ETT, TCC and TNC are involved in transactions relating to the transfer to ETT of other transmission assets, which are in various stages of review and approval. In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the Competitive Renewable Energy Zone (CREZ) initiative. The CREZ initiative is the development of 2,400 miles of new transmission lines to transport electricity from 18,000 MWs of planned wind farm capacity in west Texas to rapidly growing cities in eastern Texas. In March 2009, the PUCT issued an order pursuant to a January 2009 decision that authorized ETT to pursue the construction of $841 million of new CREZ transmission assets.

Stall Unit

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

Turk Plant

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

<u>Virginia Rate Matters</u>

Virginia E&R Costs Recovery Filing

Due to the recovery provisions in Virginia law, APCo has been deferring incremental E&R costs as incurred, excluding the equity return on non-CWIP capital investments, pending future recovery. In October 2008, the Virginia SCC approved a stipulation agreement to recover $61 million of incremental E&R costs incurred from October 2006 to December 2007 through a surcharge in 2009 which will have a favorable effect on cash flows of $61 million and on net income for the previously unrecognized equity portion of the carrying costs of approximately $11 million.

The Virginia E&R cost recovery mechanism under Virginia law ceased effective with costs incurred through December 2008. However, the 2007 amendments to Virginia's electric utility restructuring law provide for a rate adjustment clause to be requested in 2009 to recover incremental E&R costs incurred through December 2008. Under this amendment, APCo will request recovery of its 2008 unrecovered incremental E&R costs in a planned May 2009 filing. As of March 31, 2009, APCo has $109 million of deferred Virginia incremental E&R costs (excluding $22 million of unrecognized equity carrying costs). The $109 million consists of $6 million of over recovery of costs collected from the 2008 surcharge, $36 million approved by the Virginia SCC related to the 2009 surcharge and $79 million, representing costs deferred during 2008, to be included in the 2009 E&R filing, for collection in 2010.

If the Virginia SCC were to disallow a material portion of APCo's 2008 deferred incremental E&R costs, it would have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant

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

In June 2007, APCo sought pre-approval from the WVPSC for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing finance costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. In March 2008, the WVPSC granted APCo the CPCN to build the plant and approved the requested cost recovery. In March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed IGCC plant. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009. The $45 million included 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 carrying cost on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered.

The Virginia SCC issued an order in April 2008 denying APCo's requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. 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 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. Various parties, including APCo, filed comments but the WVPSC has not taken any action.

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

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.

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 demonstration 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. RWE AG, a German electric power and natural gas public utility, is participating in the project and is providing some funding to offset APCo's costs. APCo's estimated cost for its share of the facilities is $73 million. Through March 31, 2009, APCo incurred $45 million in capitalized project costs which are included in Regulatory Assets. APCo earns a return on the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the Virginia SCC in November 2008. APCo plans to seek recovery for the CO_2 capture and storage project costs including a return on the additional investment since June 2008 in its next Virginia and West Virginia base rate filings which are expected to be filed in 2009. If a significant portion of the deferred project costs are excluded from base rates and ultimately disallowed in future Virginia or West Virginia rate proceedings, it could have an adverse effect on future net income and cash flows.

<u>West Virginia Rate Matters</u>

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

In March 2009, APCo and WPCo filed an annual ENEC filing with the WVPSC for an increase of approximately $442 million for incremental fuel, purchased power and environmental compliance project expenses, to become effective July 2009. Within the filing, APCo and WPCo requested the WVPSC to allow APCo and WPCo to temporarily adopt a modified ENEC mechanism due to the distressed economy. The proposed modified ENEC mechanism provides that all deferred ENEC amounts as of June 30, 2009 be recovered over a five-year period beginning in July 2009. The mechanism also extends cost projections out for a period of three years through June 30, 2012 and provides for three annual increases to recover projected future ENEC cost increases. APCo and WPCo are also requesting all deferred amounts that exceed the deferred amounts that would have existed under the traditional ENEC mechanism be subject to a carrying charge based upon APCo's and WPCo's weighted average cost of capital. As filed, the modified ENEC mechanism would produce three annual increases, including carrying charges, of $189 million, $166 million and $172 million, effective July 2009, 2010 and 2011, respectively.

In March 2009, the WVPSC issued an order suspending the rate increase request until December 2009. In April 2009, APCo and WPCo filed a motion for approval of an interim rate increase of $180 million, effective July 2009 and subject to refund pending the final adjudication of the ENEC by December 2009. In April 2009, the WVPSC granted intervention to several parties and heard oral arguments from APCo, WPCo and intervenors on the requested interim ENEC filing. If the WVPSC were to disallow a material portion of APCo's and WPCo's requested increase, it would have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant

See "APCo's Filings for an IGCC Plant" section within "Virginia Rate Matters" for disclosure.

Mountaineer Carbon Capture Project

See "Mountaineer Carbon Capture Project" section within "Virginia Rate Matters" for disclosure.

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 included a $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. In addition, I&M proposed to share with customers, through a proposed tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In December 2008, I&M and all of the intervenors jointly filed a settlement agreement with the IURC proposing to resolve all of the issues in the case. The settlement agreement incorporated the $69 million annual reduction in revenues from depreciation rate reduction in the development of the agreed to revenue increase of $44 million including a $22 million increase in revenue from base rates with an authorized return on equity of 10.5% and a $22 million initial increase in tracker revenue for PJM, net emission allowance and DSM costs. The agreement also establishes an off-system sales sharing mechanism and other provisions which include continued funding for the eventual decommissioning of the Cook Nuclear Plant. In March 2009, the IURC approved the settlement agreement, with modifications, that provides for an annual increase in revenues of $42 million including a $19 million increase in revenue from base rates, net of the depreciation rate reduction, and a $23 million increase in tracker revenue. The IURC order removed base rate recovery of the DSM costs but established a tracker with an initial zero amount for DSM costs, adjusted the sharing of off-system sales margins to 50% above the $37.5 million included in base rates and approved the recovery of $7.3 million of previously expensed NSR and OPEB costs which favorably affected first quarter of 2009 net income. In addition, the IURC order requires I&M to review and file a final report by December 2009 on the effectiveness of the Interconnection Agreement including I&M's relationship with PJM.

Rockport and Tanners Creek Plants

In January 2009, I&M filed a petition with the IURC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to use advanced coal technology which would allow I&M to reduce airborne emissions of NO_x and mercury from its existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition is requesting approval to construct and recover the costs of selective non-catalytic reduction (SNCR) systems at the Tanners Creek Plant and to recover the costs of activated carbon injection (ACI) systems on both generating units at the Rockport Plant. I&M is requesting to depreciate the ACI systems over an accelerated 10-year period and the SNCR systems over the remaining useful life of the Tanners Creek generating units. I&M requested the IURC to approve a rate adjustment mechanism of unrecovered carrying costs during construction and a return on investment, depreciation expense and operation and maintenance costs, including consumables and new emission allowance costs, once the projects are placed in service. I&M also requested the IURC to authorize the deferral of the cost of service of these projects and carrying costs until such costs are recognized in the requested rate adjustment mechanism. Through March 2009, I&M incurred $9 million and $6 million in capitalized project costs related to the Rockport and Tanners Creek Plants, respectively, which are included in Construction Work in Progress. In March 2009, the IURC issued a prehearing conference order setting a procedural schedule. Since the Indiana base rate order included recovery of emission allowance costs, that portion of this request will be eliminated. An order is expected by the third quarter of 2009. Management is unable to predict the outcome of this petition.

Indiana Fuel Clause Filing

In January 2009, I&M filed with the IURC an application to increase its fuel adjustment charge by approximately $53 million for April through September 2009. The filing included an under-recovery for the period ended November 2008, mainly as a result of the extended outage of the Cook Plant Unit 1 (Unit 1) due to fire damage to the main turbine and generator, increased coal prices and a projection for the future period of fuel costs including Unit 1 fire related outage replacement power costs. The filing also included an adjustment, beginning coincident with the receipt of insurance proceeds, to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Unit 1 accidental outage policy. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. I&M reached an agreement in February 2009 with intervenors, which was approved by the IURC in March 2009, to collect the under-recovery over twelve months instead of over six months as proposed. Under the order, the fuel factor will go into effect, subject to refund, and a subdocket will be established to consider issues relating to the Unit 1 fire outage, the use of the insurance proceeds and I&M's fuel procurement practices. The order provides for the fire outage issues to be resolved subsequent to the date Unit 1 returns to service, which if temporary repairs are successful, could occur as early as October 2009. Management cannot predict the outcome of the pending proceedings, including the treatment of the insurance proceeds, and whether any fuel clause revenues will have to be refunded as a result.

Michigan Rate Matters

In March 2009, I&M filed with the Michigan Public Service Commission its 2008 power supply cost recovery reconciliation. The filing also included an adjustment to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Cook Plant Unit 1 accidental outage policy. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. Management is unable to predict the outcome of this proceeding and its possible effect on future net income and cash flows.

Oklahoma Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

Proceedings addressing PSO's historic fuel costs from 2001 through 2006 remain open at the OCC due to the issue of the allocation of off-system sales margins among the AEP operating companies in accordance with a FERC-approved allocation agreement.

In 2002, PSO under-recovered $42 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to 2002. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed an ALJ recommendation that concluded it was a FERC jurisdictional matter which allowed PSO to retain the $42 million it recovered from ratepayers. The OIEC requested that PSO be required to refund the $42 million through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending. For further discussion and estimated effect on net income, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

2007 Fuel and Purchased Power

In September 2008, the OCC initiated a review of PSO's generation, purchased power and fuel procurement processes and costs for 2007. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

2008 Oklahoma Base Rate Filing

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million (later adjusted to $127 million) on an annual basis. PSO has been recovering costs related to new peaking units recently placed into service through a Generation Cost Recovery Rider (GCRR). Subsequent to implementation of the new base rates, the GCRR will terminate and PSO will recover these costs through the new base rates. Therefore, PSO's net annual requested increase in total revenues was actually $117 million (later adjusted to $111 million). The proposed revenue requirement reflected a return on equity of 11.25%.

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues and a 10.5% return on equity. The rate increase includes a $59 million increase in base rates and a $22 million increase for costs to be recovered through riders outside of base rates. The $22 million increase includes $14 million for purchase power capacity costs and $8 million for the recovery of carrying costs associated with PSO's program to convert overhead distribution lines to underground service. The $8 million recovery of carrying costs associated with the overhead to underground conversion program will occur only if PSO makes the required capital expenditures. The final order approved lower depreciation rates and also provides for the deferral of $6 million of generation maintenance expenses to be recovered over a six-year period. This deferral was recorded in the first quarter of 2009. Additional deferrals were approved for distribution storm costs above or below the amount included in base rates and for certain transmission reliability expenses. The new rates reflecting the final order were implemented with the first billing cycle of February 2009.

PSO filed an appeal with the Oklahoma Supreme Court challenging an adjustment the OCC made on prepaid pension funding contained within the OCC final order. In February 2009, the Oklahoma Attorney General and several intervenors also filed appeals with the Oklahoma Supreme Court raising several issues. If the Attorney General and/or the intervenor's Supreme Court appeals are successful, it could have an adverse effect on future net income and cash flows.

Louisiana Rate Matters

2008 Formula Rate Filing

In April 2008, SWEPCo filed the first formula rate plan (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 August 2008, SWEPCo implemented the FRP rates, subject to refund. No provision for refund has been recorded as SWEPCo believes that the rates as implemented are in compliance with the FRP methodology approved by the LPSC. The LPSC has not approved the rates being collected. If the rates are not approved as filed, it could have an adverse effect on future net income and cash flows.

2009 Formula Rate Filing

In April 2009, SWEPCo filed the second FRP which would increase its annual Louisiana retail rates by an additional $4 million in August 2009 pursuant to the formula rate methodology. SWEPCo believes that the rates as filed are in compliance with the FRP methodology previously approved by the LPSC.

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 $385 million, excluding AFUDC, and is expected to be in-service in mid-2010. The Louisiana Department of Environmental Quality issued an air permit for the Stall unit in March 2008.

In March 2007, the PUCT approved SWEPCo's request for a certificate of necessity for the facility based on a prior cost estimate. In July 2008, a Louisiana ALJ issued a recommendation that SWEPCo be authorized to construct, own and operate the Stall Unit and recommended that costs be capped at $445 million (excluding transmission). In October 2008, the LPSC issued a final order effectively approving the ALJ recommendation. In December 2008, SWEPCo submitted an amended filing seeking approval from the APSC to construct the unit. The APSC staff filed testimony in March 2009 supporting the approval of the plant. The APSC staff also recommended that costs be capped at $445 million (excluding transmission). A hearing that had been scheduled for April 2009 was cancelled and the APSC will issue its decision based on the amended application and prefiled testimony. Since we and the APSC are the only two parties to the proceeding, we believe that the APSC will approve our request.

If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized construction costs including any cancellation fees. As of March 31, 2009, SWEPCo has capitalized construction costs of $291 million (including AFUDC) and has contractual construction commitments of an additional $74 million. As of March 31, 2009, if the plant had been cancelled, cancellation fees of $40 million would have been required in order to terminate the 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. 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. During 2007, OMPA exercised its participation option. During the first quarter of 2009, AECC and ETEC exercised their participation options and paid SWEPCo $104 million. SWEPCo recorded a $2.2 million gain from the transactions. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's portion estimated to cost $1.2 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 Turk Plant. Certain landowners have appealed the APSC's decision 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 previously estimated $1.522 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. 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 emission costs exceed the restrictions, it could have a material adverse effect 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.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. 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 2009, SWEPCo filed a motion to dismiss the appeal. In March 2009, the motion was granted.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant's permit is heard. Hearings on the air permit appeal is scheduled for June 2009. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers a potential wetlands impact on approximately 2.5 acres at the Turk Plant. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas of the Turk Plant. The impact on the construction schedule and workforce is currently being evaluated by management.

In January and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications 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. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor's Commission on Global Warming issued its final report to the governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build and operate 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 costs incurred plus related shutdown costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of March 31, 2009, SWEPCo has capitalized approximately $480 million of expenditures (including AFUDC) and has contractual construction commitments for an additional $655 million. As of March 31, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $100 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.

Arkansas Base Rate Filing

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to recover financing costs related to the construction of the Stall and Turk generating facilities. These financing costs are currently being capitalized as AFUDC in Arkansas. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

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 the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 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 are 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 of any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. The balance in the reserve for future settlements as of March 2009 was $34 million. As of March 31, 2009, there were no in-process settlements.

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 available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

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 state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. 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. In January and March 2009, AEP received retail rate increases in Tennessee and Indiana, respectively, that recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, AEP is now recovering approximately 98% of the lost T&O transmission revenues. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

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. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is 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 to reflect the resultant additional transmission cost reductions. 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 the AEP East companies' cost of service. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, established a settlement proceeding with an ALJ, and delayed the requested October 2008 effective date for five months. The requested increase, which the AEP East companies began billing in April 2009 for service as of March 1, 2009, will produce a $63 million annualized increase in revenues. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio are not directly affected. Retail rates for CSPCo and OPCo would be increased through the TCRR totaling approximately $10 million and $13 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. In October 2008, AEP filed the required compliance filing, and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing. Under the formula, rates will be updated effective July 1, 2009, and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies shared a portion of such revenues with their wholesale and retail customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund. In January 2009, SWEPCo refunded approximately $13 million to FERC wholesale customers. In February 2009, SWEPCo filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction amount to be included in the March 2009 fuel cost report submitted to the PUCT. PSO began refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle. TCC and TNC in Texas filed applications in April 2009 to initiate proceedings as a result of the FERC ruling. TCC and TNC propose to use the refund to reduce its AMS investment as discussed in the "Advanced Metering System" section within "Texas Rate Matters". SWEPCo is working with the APSC and the LPSC to determine the effect the FERC order will have on retail rates. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding future regulatory proceedings is adequate.

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 2008 Annual Report should be read in conjunction with this report.

GUARANTEES

We record certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." In addition, we adopted 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" effective December 31, 2008. 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 March 31, 2009, the maximum future payments for all the LOCs issued 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, are approximately $120 million with maturities ranging from May 2009 to March 2010.

We have 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 March 31, 2009, $372 million of letters of credit were issued by subsidiaries under the $650 million 3-year credit agreement to support variable rate Pollution Control Bonds. In April 2009, the $350 million 364-day credit agreement expired.

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 March 31, 2009, SWEPCo has collected approximately $39 million through a rider for final mine closure costs, of which approximately $3 million is recorded in Other Current Liabilities, $20 million is recorded in Deferred Credits and Other and approximately $16 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

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

Indemnifications And Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sales agreements is discussed in the 2008 Annual Report, "Dispositions" section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.2 billion. Approximately $1 billion of the maximum exposure relates to the Bank of America (BOA) litigation (see "Enron Bankruptcy" section of this note), of which the probable payment/performance risk is $435 million and is recorded in Deferred Credits and Other on our Condensed Consolidated Balance Sheets as of March 31, 2009. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Master Lease Agreements

We lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified us in November 2008 that they elected to terminate our Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2010 and 2011, we will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, we signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. We expect to enter into additional replacement leasing arrangements for the equipment affected by this notification prior to the termination dates of 2010 and 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual 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 actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At March 31, 2009, the maximum potential loss for these lease agreements was approximately $8 million assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $20 million for I&M and $23 million for SWEPCo for the remaining railcars as of March 31, 2009.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five-year lease term to 77% at the end of the 20-year term of the projected fair market value of the equipment. I&M

and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss.

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 CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. modified certain units at their jointly-owned coal-fired generating units in violation of the NSR requirements of the CAA.

A case remains pending that could affect CSPCo's share of jointly-owned Beckjord Station. The Beckjord case had a liability trial in 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. Beckjord is operated by Duke Energy Ohio, Inc.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, we might have for civil penalties under the pending CAA proceedings for Beckjord. We are also unable to predict the timing of resolution of these matters. If we do not prevail, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through future regulated rates or market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect our net income, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. 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 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 a permit alteration issued by the Texas Commission on Environmental Quality 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 actions 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 concluded in 2006. 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 which we provided in 2007. 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.

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 and started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $4 million of expense during 2008. Based upon updated information, I&M recorded additional expense of $3 million in March 2009. As the remediation work is completed, I&M's cost may continue to increase. I&M cannot predict the amount of additional cost, if any.

Defective Environmental Equipment

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

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

The refueling outage scheduled for the fall of 2009 for Unit 1 was rescheduled to the spring of 2010. Management anticipates that the loss of capacity from Unit 1 will not affect I&M's ability to serve customers due to the existence of sufficient generating capacity in the AEP Power Pool.

I&M maintains property insurance through NEIL with a $1 million deductible. As of March 31, 2009, we recorded $34 million in Prepayments and Other on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursement from NEIL for the cost incurred to date to repair the property damage. 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 for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In the first quarter of 2009, I&M recorded $54 million in revenues, including $9 million that were deferred at December 31, 2008, related to the accidental outage policy. In order to hold customers harmless, in the first quarter of 2009, I&M applied $20 million of the accidental outage insurance proceeds to reduce fuel underrecoveries reflecting recoverable fuel costs as if Unit 1 were operating. 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.

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 gain in January 2008 under Asset Impairments and Other Related Charges on our Condensed Consolidated Statements of Income. This settlement related to the Plaquemine Cogeneration Facility which we sold in 2006.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute is being litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

In February 2004, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We objected to Enron's attempted rejection of these agreements and filed an adversary proceeding 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 in the Southern District of Texas the four counts alleging breach of contract, fraud and negligent misrepresentation. 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 dismissed our claims. In December 2007, the judge held that BOA is entitled to recover damages of approximately $347 million plus interest. 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. The appeal was briefed during the first quarter of 2009. Oral argument remains to be scheduled.

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 $435 million and $433 million including interest at March 31, 2009 and December 31, 2008, respectively. 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 in Federal District Court, Columbus, Ohio against AEP, certain executives and AEP's ERISA Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. 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 2006, the court entered judgment in the remaining case, denying the plaintiff's motion for class certification and dismissing all claims without prejudice. In 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 March 2009, the court granted a motion to intervene on behalf of an individual seeking to intervene as a new plaintiff. We will 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. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we recorded for the remaining cases is adequate.

Rail Transportation Litigation

In October 2008, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as co-owners of Oklaunion Plant, filed a lawsuit 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 assumed the duties of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. In December 2008, the court denied our motion to dismiss the case. We intend to vigorously defend against these allegations. We believe a provision recorded in 2008 should be sufficient.

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. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. We believe a provision recorded in 2008 should be sufficient. 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. Management is unable to predict the outcome of these proceedings or their ultimate impact on future net income and cash flows.

5. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the three months ended March 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 10	$ 10
Interest Cost	63	63	27	28
Expected Return on Plan Assets	(80)	(84)	(20)	(28)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	15	9	11	3
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 20

We sponsor several trust funds with significant investments intended 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 from the December 31, 2008 balances due to decreases in the equity and fixed income markets. Although the asset values are currently lower than at year end, this decline has not affected the funds' ability to make their required payments.

6. BUSINESS SEGMENTS

As outlined in our 2008 Annual Report, our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

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

AEP River Operations
- Commercial Barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 13% for steel and 19% for other commodities.

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

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

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- 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 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

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

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended March 31, 2009						
Revenues from:						
External Customers	$ 3,267 (d)	$ 123	$ 87	$ (19)	$ -	$ 3,458
Other Operating Segments	- (d)	6	5	22	(33)	-
Total Revenues	$ 3,267	$ 129	$ 92	$ 3	$ (33)	$ 3,458
Net Income (Loss)	$ 346	$ 11	$ 24	$ (18)	$ -	$ 363
Less: Net Income Attributable to Noncontrolling Interests	(2)	-	-	-	-	(2)
Net Income (Loss) Attributable to AEP Shareholders	344	11	24	(18)	-	361
Less: Preferred Stock Dividend Requirements of Subsidiaries	(1)	-	-	-	-	(1)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 343	$ 11	$ 24	$ (18)	$ -	$ 360

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended March 31, 2008						
Revenues from:						
External Customers	$ 3,010 (d)	$ 138	$ 271	$ 48	$ -	$ 3,467
Other Operating Segments	284 (d)	4	(212)	(43)	(33)	-
Total Revenues	$ 3,294	$ 142	$ 59	$ 5	$ (33)	$ 3,467
Net Income	$ 413	$ 7	$ 1	$ 155	$ -	$ 576
Less: Net Income Attributable to Noncontrolling Interests	(2)	-	-	-	-	(2)
Net Income Attributable to AEP Shareholders	411	7	1	155	-	574
Less: Preferred Stock Dividend Requirements of Subsidiaries	(1)	-	-	-	-	(1)
Earnings Attributable to AEP Common Shareholders	$ 410	$ 7	$ 1	$ 155	$ -	$ 573

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (c)	Consolidated
			(in millions)			
March 31, 2009						
Total Property, Plant and Equipment	$ 49,454	$ 368	$ 570	$ 10	$ (238)	$ 50,164
Accumulated Depreciation and Amortization	16,708	76	147	8	(26)	16,913
Total Property, Plant and Equipment – Net	$ 32,746	$ 292	$ 423	$ 2	$ (212)	$ 33,251
Total Assets	$ 44,278	$ 416	$ 795	$ 14,729	$ (14,353)(b)	$ 45,865

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

(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 2006. The cash settlement of $255 million ($164 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 with AEPEP in Revenues from Other Operating Segments of $(5) million and $212 million for the three months ended March 31, 2009 and 2008, respectively. The Generation and Marketing segment also reports these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP will end in December 2009.

7. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

Objectives for Utilization of Derivative Instruments

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

Strategies for Utilization of Derivative Instruments to Achieve Objectives

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value based on our open trading positions by utilizing both economic and formal SFAS 133 hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under SFAS 133. Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of SFAS 133.

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

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

Notional Volume of Derivative Instruments
March 31, 2009

Primary Risk Exposure		Volume	Unit of Measure
		(in millions)	
Commodity:			
Power		351	MWHs
Coal		51	Tons
Natural Gas		211	MMBtu
Heating Oil and Gasoline		4	Gallons
Interest Rate	$	413	USD
Interest Rate and Foreign Currency	$	501	USD

Fair Value Hedging Strategies

At certain times, we enter into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Currently, this strategy is not actively employed.

Cash Flow Hedging Strategies

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

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

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. We do not hedge all foreign currency exposure.

Accounting for Derivative Instruments and the Impact on Our Financial Statements

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

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

According to FSP FIN 39-1, we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2009 and December 31, 2008 balance sheets, we netted $74 million and $11 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $117 million and $43 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

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

Fair Value of Derivative Instruments
March 31, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency**	**Other (b)**	**Total**
			(in millions)		
Current Risk Management Assets	$ 2,209	$ 47	$ 1	$ (1,964)	$ 293
Long-Term Risk Management Assets	1,087	2	-	(672)	417
Total Assets	3,296	49	1	(2,636)	710
Current Risk Management Liabilities	2,121	35	4	(1,981)	179
Long-Term Risk Management Liabilities	902	1	4	(733)	174
Total Liabilities	3,023	36	8	(2,714)	353
Total MTM Derivative Contract Net Assets (Liabilities)	$ 273	$ 13	$ (7)	$ 78	$ 357

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Condensed Consolidated Balance Sheet on a net basis in accordance with FIN 39 "Offsetting of Amounts Related to Certain Contracts."
(b) Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with FSP FIN 39-1 and dedesignated risk management contracts.

The table below presents our MTM activity of derivative risk management contracts for the three months ended March 31, 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2009

Location of Gain (Loss)	**(in millions)**	
Utility Operations Revenue	$	65
Other Revenue		13
Regulatory Assets		(1)
Regulatory Liabilities		74
Total Gain on Risk Management Contracts	$	151

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Condensed Consolidated Statements of Income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Condensed Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Condensed Consolidated Statements of Income depending on the relevant facts and circumstances. However, unrealized and realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with SFAS 71.

Accounting for Fair Value Hedging Strategies

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

We record realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Condensed Consolidated Statements of Income. During the three months ended March 31, 2009, we did not employ any fair value hedging strategies. During the three months ended March 31, 2008, we designated interest rate derivatives as fair value hedges and did not recognize any hedge ineffectiveness related to these derivative transactions.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale in our Condensed Consolidated Statements of Income, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to commodities. During the three months ended March 31, 2009 and 2008, we recognized immaterial amounts in Net Income related to hedge ineffectiveness.

Beginning in 2009, we executed financial heating oil and gasoline derivative contracts to hedge the price risk of our diesel fuel and gasoline purchases. We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Other Operation and Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Condensed Consolidated Statements of Income. We do not hedge all fuel price risk exposure. During the three months ended March 31, 2009, we recognized no hedge ineffectiveness related to this hedge strategy.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2009 and 2008, we recognized immaterial amounts in Net Income related to hedge ineffectiveness.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Depreciation and Amortization expense in our Condensed Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. We do not hedge all foreign currency exposure. During the three months ended March 31, 2009 and 2008, we recognized no hedge ineffectiveness related to this hedge strategy.

The following table provides details 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 January 1, 2009 to March 31, 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Beginning Balance in AOCI as of January 1, 2009	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(3)	-	(3)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet			
Utility Operations Revenue	(2)	-	(2)
Other Revenue	(2)	-	(2)
Purchased Electricity for Resale	8	-	8
Interest Expense	-	1	1
Regulatory Assets	2	-	2
Regulatory Liabilities	(1)	-	(1)
Ending Balance in AOCI as of March 31, 2009	$ 9	$ (28)	$ (19)

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

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 40	$ 1	$ 41
Hedging Liabilities (a)	(27)	(8)	(35)
AOCI Gain (Loss) Net of Tax	9	(28)	(19)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	8	(6)	2

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

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2009, the maximum length of time that we are hedging (with SFAS 133 designated contracts) our exposure to variability in future cash flows related to forecasted transactions is 44 months.

Credit Risk

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

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

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), we are obligated to post an amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We believe that a downgrade below investment grade is unlikely. As of March 31, 2009, the aggregate value of such contracts was $127 million and AEP was not required to post any collateral. We would have been required to post $127 million of collateral at March 31, 2009, if our credit ratings had declined below investment grade of which $123 million was attributable to our RTO and ISO activities.

FAIR VALUE MEASUREMENTS

SFAS 157 Fair Value Measurements

As described in our 2008 Annual Report, 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). The Derivatives, Hedging and Fair Value Measurements note within the 2008 Annual Report should be read in conjunction with this report.

The following tables set forth by level, within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009 and December 31, 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 March 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents					
Cash and Cash Equivalents (a)	$ 637	$ -	$ -	$ 58	$ 695
Debt Securities (b)	-	15	-	-	15
Total Cash and Cash Equivalents	637	15	-	58	710
Other Temporary Investments					
Cash and Cash Equivalents (a)	107	-	-	27	134
Debt Securities (c)	56	-	-	-	56
Equity Securities (d)	25	-	-	-	25
Total Other Temporary Investments	188	-	-	27	215
Risk Management Assets					
Risk Management Contracts (e)	71	3,112	99	(2,648)	634
Cash Flow Hedges (e)	8	41	-	(8)	41
Dedesignated Risk Management Contracts (f)	-	-	-	35	35
Total Risk Management Assets	79	3,153	99	(2,621)	710
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (g)	-	15	-	9	24
Debt Securities (h)	-	764	-	-	764
Equity Securities (d)	419	-	-	-	419
Total Spent Nuclear Fuel and Decommissioning Trusts	419	779	-	9	1,207
Total Assets	$ 1,323	$ 3,947	$ 99	$ (2,527)	$ 2,842
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (e)	$ 86	$ 2,910	$ 13	$ (2,691)	$ 318
Cash Flow Hedges (e)	3	40	-	(8)	35
Total Risk Management Liabilities	$ 89	$ 2,950	$ 13	$ (2,699)	$ 353

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

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

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

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

(c) Amounts represent debt-based mutual funds.

(d) Amount represents publicly traded equity securities and equity-based mutual funds.

(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 MTM value will be amortized into Utility Operations Revenues over the remaining life of the contracts.

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

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

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 March 31, 2009	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of January 1, 2009	$ 49	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets)	(12)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	59	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	-	-
Transfers in and/or out of Level 3 (c)	(25)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	15	-	-
Balance as of March 31, 2009	$ 86	$ -	$ -

Three Months Ended March 31, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of January 1, 2008	$ 49	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets)	(3)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	5	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	(96)	-
Transfers in and/or out of Level 3 (c)	(5)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	3	-	-
Balance as of March 31, 2008	$ 49	$ 22	$ 17

(a) Included in revenues on our Condensed Consolidated Statements of Income.
(b) Includes principal amount of securities settled during the period.
(c) "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.
(d) "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 liabilities/assets.

8. INCOME TAXES

We are no longer subject to U.S. federal examination for years before 2000. We have completed the exam for the years 2001 through 2006 and have issues that we are pursuing at the appeals level. 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.

9. FINANCING ACTIVITIES

Common Stock

In April 2009, we issued 69 million shares of common stock at $24.50 per share for net proceeds of $1.64 billion. We used $1.25 billion of the proceeds to repay part of the cash drawn under our credit facilities.

Long-term Debt

Type of Debt	March 31, 2009	December 31, 2008
	(in millions)	
Senior Unsecured Notes	$ 11,890	$ 11,069
Pollution Control Bonds	2,080	1,946
Notes Payable	224	233
Securitization Bonds	2,051	2,132
Junior Subordinated Debentures	315	315
Spent Nuclear Fuel Obligation (a)	264	264
Other Long-term Debt	88	88
Unamortized Discount (net)	(69)	(64)
Total Long-term Debt Outstanding	16,843	15,983
Less Portion Due Within One Year	939	447
Long-term Portion	$ 15,904	$ 15,536

(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 $304 million and $301 million at March 31, 2009 and December 31, 2008, 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 three months of 2009 are shown in the tables below.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Issuances:				
APCo	Senior Unsecured Notes	$ 350	7.95	2020
I&M	Senior Unsecured Notes	475	7.00	2019
I&M	Pollution Control Bonds	50	6.25	2025
I&M	Pollution Control Bonds	50	6.25	2025
PSO	Pollution Control Bonds	34	5.25	2014
Total Issuances		$ 959 (a)		

The above borrowing arrangements do not contain guarantees, collateral or dividend restrictions.

(a) Amount indicated on statement of cash flows of $947 million is net of issuance costs and premium or discount.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
OPCo	Notes Payable	$ 1	6.27	2009
OPCo	Notes Payable	4	7.21	2009
SWEPCo	Notes Payable	1	4.47	2011
Non-Registrant:				
AEP Subsidiaries	Notes Payable	3	Variable	2017
AEGCo	Senior Unsecured Notes	4	6.33	2037
TCC	Securitization Bonds	31	5.56	2010
TCC	Securitization Bonds	50	4.98	2010
Total Retirements and Principal Payments		$ 94		

During 2008, we chose to begin eliminating our auction-rate debt position due to market conditions. As of March 31, 2009, $272 million of our auction-rate tax-exempt long-term debt, with rates ranging between 1.676% and 13%, remained outstanding with rates reset every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. Approximately $218 million of the $272 million of outstanding auction-rate debt relates to a lease structure with JMG that we are unable to refinance without their consent. The rates for this debt are at contractual maximum rate of 13%. The initial term for the JMG lease structure matures on March 31, 2010. We are evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO.

During the first quarter of 2009, we issued $134 million of Pollution Control Bonds which were previously held by trustees on our behalf. As of March 31, 2009, trustees held, on our behalf, $195 million of our remaining 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:

	March 31, 2009		December 31, 2008	
Type of Debt	Outstanding Amount (in thousands)	Interest Rate (a)	Outstanding Amount (in thousands)	Interest Rate (a)
Line of Credit – AEP	$ 1,969,000 (b)	1.22% (c)	$ 1,969,000	2.28% (c)
Line of Credit – Sabine Mining Company (d)	6,559	1.82%	7,172	1.54%
Total	$ 1,975,559		$ 1,976,172	

(a) Weighted average rate.
(b) Paid $1.25 billion with proceeds from the equity issuance in April 2009.
(c) Rate based on LIBOR.
(d) Sabine Mining Company is consolidated under FIN 46R. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

As of March 31, 2009, we have credit facilities totaling $3 billion to support our commercial paper program which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $46 million following its bankruptcy. The facilities are structured as two $1.5 billion credit facilities of which $750 million may be issued under each credit facility as letters of credit.

We have a $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 March 31, 2009, $372 million of letters of credit were issued by subsidiaries under the $650 million 3-year agreement to support variable rate Pollution Control Bonds. In April 2009, the $350 million 364-day credit agreement expired.

APPALACHIAN POWER COMPANY

AND SUBSIDIARIES

Results of Operations

First Quarter of 2009 Compared to First Quarter of 2008

Reconciliation of First Quarter of 2008 to First Quarter of 2009
Net Income
(in millions)

First Quarter of 2008		$	55
Changes in Gross Margin:			
Retail Margins	87		
Off-system Sales	(47)		
Other	1		
Total Change in Gross Margin			41
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	12		
Depreciation and Amortization	(7)		
Carrying Costs Income	(6)		
Other Income	(1)		
Interest Expense	(6)		
Total Change in Operating Expenses and Other			(8)
Income Tax Expense			(14)
First Quarter of 2009		$	74

Net Income increased $19 million to $74 million in 2009. The key drivers of the increase were a $41 million increase in Gross Margin, partially offset by a $14 million increase in Income Tax Expense and an $8 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 Margins increased $87 million primarily due to the following:
  - A $49 million increase in rate relief primarily due to the impact of the Virginia base rate order issued in October 2008, an increase in the recovery of E&R costs in Virginia and an increase in the recovery of construction financing costs in West Virginia.
  - A $39 million increase due to a decrease in sharing of off-system sales margins with customers in Virginia and West Virginia.
  - A $7 million increase due to new rates effective January 2009 for a power supply contract with KGPCo.
  - A $3 million increase in residential and commercial revenue primarily due to increased usage resulting from a 5% increase in heating degree days.

  These increases were partially offset by:
  - A $14 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
- Margins from Off-system Sales decreased $47 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher 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 lower employee-related expenses and generation plant maintenance.
- Depreciation and Amortization expenses increased $7 million primarily due to a greater depreciation base resulting from asset improvements and the amortization of carrying charges and depreciation expenses that are being collected through the Virginia E&R surcharges.
- Carrying Costs Income decreased $6 million due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Interest Expense increased $6 million primarily due to an increase in long-term debt issuances.
- Income Tax Expense increased $14 million primarily due to an increase in pretax book income, partially offset by state income tax adjustments recorded in 2008.

Financial Condition

Credit Ratings

APCo's credit ratings as of March 31, 2009 were as follows:

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

S&P has APCo on stable outlook, while Fitch has APCo on negative outlook. In February 2009, Moody's changed its rating outlook for APCo from negative to stable due to recent rate recoveries in Virginia and West Virginia. If APCo receives a downgrade from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the three months ended March 31, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,996	$ 2,195
Cash Flows from (Used for):		
Operating Activities	(29,207)	118,832
Investing Activities	(220,590)	(409,179)
Financing Activities	250,355	290,804
Net Increase in Cash and Cash Equivalents	558	457
Cash and Cash Equivalents at End of Period	$ 2,554	$ 2,652

Operating Activities

Net Cash Flows Used for Operating Activities were $29 million in 2009. APCo produced Net Income of $74 million during the period and had noncash expense items of $70 million for Depreciation and Amortization and $80 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. The $116 million cash outflow from Accounts Payable was primarily due to APCo's provision for revenue refund of $77 million which was paid in the first quarter 2009 to the AEP West companies as part of the FERC's recent order on the SIA. The $71 million change in Fuel Over/Under-Recovery, Net resulted in a net under-recovery of fuel cost in both Virginia and West Virginia.

Net Cash Flows from Operating Activities were $119 million in 2008. APCo produced Net Income of $55 million during the period and a noncash expense item of $63 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 current period activity in working capital relates to a number of items. The $32 million cash inflow from Accounts Receivable, Net was primarily due to a settlement of allowance sales to affiliated companies. The $20 million cash inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory to reflect planned outages. The $27 million change in Fuel Over/Under-Recovery, Net resulted in a net under-recovery of fuel cost in both Virginia and West Virginia.

Investing Activities

Net Cash Flows Used for Investing Activities during 2009 and 2008 were $221 million and $409 million, respectively. Construction Expenditures were $221 million and $159 million in 2009 and 2008, respectively, primarily related to transmission and distribution service reliability projects, as well as environmental upgrades for both periods. Environmental upgrades include the installation of selective catalytic reduction equipment on APCo's plants and flue gas desulfurization projects at the Amos and Mountaineer Plants. APCo's investments in the Utility Money Pool increased by $262 million in 2008. APCo forecasts approximately $368 million of construction expenditures for all of 2009, excluding AFUDC.

Financing Activities

Net Cash Flows from Financing Activities were $250 million in 2009. APCo issued $350 million of Senior Unsecured Notes in March 2009. APCo had a net decrease of $74 million in borrowings from the Utility Money Pool.

Net Cash Flows from Financing Activities were $291 million in 2008. APCo received capital contributions from the Parent of $75 million. APCo issued $500 million of Senior Unsecured Notes in March 2008. APCo had a net decrease of $275 million in borrowings from the Utility Money Pool.

Financing Activity

Long-term debt issuances and principal payments made during the first three months of 2009 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Debt	$ 350,000	7.95	2020

Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Land Note	$ 4	13.718	2026

Liquidity

The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact APCo's access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications on APCo since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on APCo's operations and ability to issue debt at reasonable interest rates.

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 May 2009. APCo issued $350 million of Senior Unsecured Notes in March 2009 that will be used to pay down its maturity. APCo will rely upon cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures.

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

Summary Obligation Information

A summary of contractual obligations is included in the 2008 Annual Report and has not changed significantly from year-end other than the debt issuances discussed in “Cash Flow” and “Financing Activity” above.

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 2008 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 2008 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 March 31, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
March 31, 2009
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 80,340	$ 6,570	$ -	$ (11,715)	$ 75,195
Noncurrent Assets	77,857	237	-	(13,323)	64,771
Total MTM Derivative Contract Assets	158,197	6,807	-	(25,038)	139,966
Current Liabilities	(47,628)	(518)	(2,697)	11,751	(39,092)
Noncurrent Liabilities	(52,445)	(41)	(1,830)	24,261	(30,055)
Total MTM Derivative Contract Liabilities	(100,073)	(559)	(4,527)	36,012	(69,147)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 58,124	$ 6,248	$ (4,527)	$ 10,974	$ 70,819

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$	56,936
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(9,387)
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		(113)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(339)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		11,027
Total MTM Risk Management Contract Net Assets		58,124
Cash Flow Hedge Contracts		6,248
DETM Assignment (d)		(4,527)
Collateral Deposits		10,974
Ending Net Risk Management Assets at March 31, 2009	$	70,819

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "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 liabilities/assets.
(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 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 March 31, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (1,815)	$ (47)	$ 1	$ -	$ -	$ -	$ (1,861)
Level 2 (b)	19,116	10,941	6,365	(511)	38	-	35,949
Level 3 (c)	5,508	2,773	1,679	1,668	219	-	11,847
Total	22,809	13,667	8,045	1,157	257	-	45,935
Dedesignated Risk Management Contracts (d)	3,739	4,862	1,894	1,694	-	-	12,189
Total MTM Risk Management Contract Net Assets	$ 26,548	$ 18,529	$ 9,939	$ 2,851	$ 257	$ -	$ 58,124

(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 contracts.

Credit Risk

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

See Note 7 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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 March 31, 2009, a near term typical change in commodity prices is not expected to have a material effect on 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:

Three Months Ended March 31, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$297	$546	$306	$151	$176	$1,096	$396	$161

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 APCo's exposure to extreme price moves. Management employs a historical-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 translated into the largest potential MTM 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 $7.8 million.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 727,959	$ 641,457
Sales to AEP Affiliates	56,231	90,090
Other	1,839	3,480
TOTAL	786,029	735,027
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	143,681	173,830
Purchased Electricity for Resale	75,816	43,199
Purchased Electricity from AEP Affiliates	197,124	189,595
Other Operation	65,502	75,531
Maintenance	55,910	57,844
Depreciation and Amortization	69,995	62,572
Taxes Other Than Income Taxes	24,103	23,991
TOTAL	632,131	626,562
OPERATING INCOME	153,898	108,465
Other Income (Expense):		
Interest Income	382	2,769
Carrying Costs Income	4,083	9,586
Allowance for Equity Funds Used During Construction	2,653	1,496
Interest Expense	(49,705)	(44,140)
INCOME BEFORE INCOME TAX EXPENSE	111,311	78,176
Income Tax Expense	36,904	22,863
NET INCOME	74,407	55,313
Preferred Stock Dividend Requirements Including Capital Stock Expense	225	238
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 74,182	$ 55,075

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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		75,000			75,000
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		39	(38)		1
TOTAL					2,154,366
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,438				(13,813)	(13,813)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $449				833	833
NET INCOME			55,313		55,313
TOTAL COMPREHENSIVE INCOME					42,333
MARCH 31, 2008	$ 260,458	$ 1,100,188	$ 884,220	$ (48,167)	$ 2,196,699
DECEMBER 31, 2008	$ 260,458	$ 1,225,292	$ 951,066	$ (60,225)	$ 2,376,591
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		26	(25)		1
TOTAL					2,356,392
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $945				1,756	1,756
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $661				1,226	1,226
NET INCOME			74,407		74,407
TOTAL COMPREHENSIVE INCOME					77,389
MARCH 31, 2009	$ 260,458	$ 1,225,318	$ 1,005,248	$ (57,243)	$ 2,433,781

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
March 31, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,554	$ 1,996
Accounts Receivable:		
Customers	158,282	175,709
Affiliated Companies	79,998	110,982
Accrued Unbilled Revenues	40,347	55,733
Miscellaneous	640	498
Allowance for Uncollectible Accounts	(6,566)	(6,176)
Total Accounts Receivable	272,701	336,746
Fuel	168,257	131,239
Materials and Supplies	78,508	76,260
Risk Management Assets	75,195	65,140
Accrued Tax Benefits	55,247	15,599
Regulatory Asset for Under-Recovered Fuel Costs	236,743	165,906
Prepayments and Other	48,669	45,657
TOTAL	937,874	838,543
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,147,818	3,708,850
Transmission	1,769,947	1,754,192
Distribution	2,539,095	2,499,974
Other	355,514	358,873
Construction Work in Progress	700,084	1,106,032
Total	9,512,458	9,427,921
Accumulated Depreciation and Amortization	2,691,689	2,675,784
TOTAL - NET	6,820,769	6,752,137
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,012,778	999,061
Long-term Risk Management Assets	64,771	51,095
Deferred Charges and Other	119,665	121,828
TOTAL	1,197,214	1,171,984
TOTAL ASSETS	$ 8,955,857	$ 8,762,664

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
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 120,481	$ 194,888
Accounts Payable:		
General	254,384	358,081
Affiliated Companies	97,749	206,813
Long-term Debt Due Within One Year – Nonaffiliated	150,017	150,017
Risk Management Liabilities	39,092	30,620
Customer Deposits	57,025	54,086
Deferred Income Taxes	107,721	-
Accrued Taxes	63,997	65,550
Accrued Interest	69,518	47,804
Other	74,269	113,655
TOTAL	1,034,253	1,221,514
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,271,191	2,924,495
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	30,055	26,388
Deferred Income Taxes	1,105,974	1,131,164
Regulatory Liabilities and Deferred Investment Tax Credits	518,038	521,508
Employee Benefits and Pension Obligations	329,245	331,000
Deferred Credits and Other	115,568	112,252
TOTAL	5,470,071	5,146,807
TOTAL LIABILITIES	6,504,324	6,368,321
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	1,225,318	1,225,292
Retained Earnings	1,005,248	951,066
Accumulated Other Comprehensive Income (Loss)	(57,243)	(60,225)
TOTAL	2,433,781	2,376,591
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 8,955,857	$ 8,762,664

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 74,407	$ 55,313
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	69,995	62,572
Deferred Income Taxes	80,375	25,066
Carrying Costs Income	(4,083)	(9,586)
Allowance for Equity Funds Used During Construction	(2,653)	(1,496)
Mark-to-Market of Risk Management Contracts	(9,433)	(1,658)
Change in Other Noncurrent Assets	(7,737)	(13,102)
Change in Other Noncurrent Liabilities	3,098	(5,555)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	64,045	32,344
Fuel, Materials and Supplies	(39,266)	20,442
Accounts Payable	(115,697)	4,235
Accrued Taxes, Net	(41,201)	(2,942)
Fuel Over/Under-Recovery, Net	(70,837)	(26,584)
Other Current Assets	(16,033)	(6,690)
Other Current Liabilities	(14,187)	(13,527)
Net Cash Flows from (Used for) Operating Activities	(29,207)	118,832
INVESTING ACTIVITIES		
Construction Expenditures	(221,053)	(158,722)
Change in Other Cash Deposits	235	-
Change in Advances to Affiliates, Net	-	(261,823)
Proceeds from Sales of Assets	228	11,366
Net Cash Flows Used for Investing Activities	(220,590)	(409,179)
FINANCING ACTIVITIES		
Capital Contribution from Parent	-	75,000
Issuance of Long-term Debt – Nonaffiliated	345,814	492,325
Change in Advances from Affiliates, Net	(74,407)	(275,257)
Retirement of Long-term Debt – Nonaffiliated	(4)	(3)
Principal Payments for Capital Lease Obligations	(848)	(1,061)
Dividends Paid on Common Stock	(20,000)	-
Dividends Paid on Cumulative Preferred Stock	(200)	(200)
Net Cash Flows from Financing Activities	250,355	290,804
Net Increase in Cash and Cash Equivalents	558	457
Cash and Cash Equivalents at Beginning of Period	1,996	2,195
Cash and Cash Equivalents at End of Period	$ 2,554	$ 2,652
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 49,390	$ 35,527
Net Cash Paid (Received) for Income Taxes	(2,683)	338
Noncash Acquisitions Under Capital Leases	151	478
Construction Expenditures Included in Accounts Payable at March 31,	88,405	83,766

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

First Quarter of 2009 Compared to First Quarter of 2008

Reconciliation of First Quarter of 2008 to First Quarter of 2009
Net Income
(in millions)

First Quarter of 2008		$	76
Changes in Gross Margin:			
Retail Margins	(19)		
Off-system Sales	(23)		
Total Change in Gross Margin			(42)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(11)		
Depreciation and Amortization	14		
Taxes Other Than Income Taxes	(1)		
Other Income	(2)		
Interest Expense	(1)		
Total Change in Operating Expenses and Other			(1)
Income Tax Expense			16
First Quarter of 2009		$	49

Net Income decreased $27 million to $49 million in 2009. The key driver of the decrease was a $42 million decrease in Gross Margin, partially offset by a $16 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 $19 million primarily due to:
  - A $14 million decrease as a result of Restructuring Transition Charge (RTC) revenues and their associated offset in fuel under-recovery in the first quarter of 2009. The PUCO allowed CSPCo to continue collecting the RTC pending the implementation of the new ESP tariffs which did not occur until March 30, 2009. In 2008, RTC revenues were recorded but were offset through the amortization of the transition regulatory assets as discussed below.
  - A $7 million decrease related to CSPCo's Unit Power Agreement for AEGCo's Lawrenceburg Plant. Permission was granted to include in fuel as a result of the ESP order.
  - A $3 million decrease in industrial revenue primarily due to lower load.

  These decreases were partially offset by:
  - A $5 million increase in fuel margins due to the deferral of fuel costs in 2009. The PUCO's March 2009 approval of CSPCo's ESP allows for the recovery of fuel and related costs incurred since January 1, 2009. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $5 million increase related to new rates implemented due to the accrual for March unbilled revenues at higher rates set by the Ohio ESP.
- Margins from Off-system Sales decreased $23 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to:
  - An $8 million increase in overhead line expenses primarily due to ice and wind storms in the first quarter of 2009.
  - An $8 million increase related to an obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of CSPCo's ESP. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $6 million increase in recoverable PJM expenses.

  These increases were partially offset by:
  - An $8 million decrease in expenses related to CSPCo's Unit Power Agreement for AEGCo's Lawrenceburg Plant primarily due to the classification of capacity and depreciation to fuel accounts pursuant to the March 2009 ESP order.
  - A $5 million decrease in employee-related expenses.
- Depreciation and Amortization decreased $14 million primarily due to the completed amortization of transition regulatory assets in December 2008.
- Income Tax Expense decreased $16 million primarily due to a decrease in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2008 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 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 $1.4 million.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 460,922	$ 505,324
Sales to AEP Affiliates	10,206	35,108
Other	608	1,217
TOTAL	471,736	541,649
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	70,944	85,127
Purchased Electricity for Resale	29,838	42,186
Purchased Electricity from AEP Affiliates	93,092	94,104
Other Operation	76,088	73,066
Maintenance	31,014	23,231
Depreciation and Amortization	34,945	48,602
Taxes Other Than Income Taxes	45,282	44,556
TOTAL	381,203	410,872
OPERATING INCOME	90,533	130,777
Other Income (Expense):		
Interest Income	240	2,339
Carrying Costs Income	1,689	1,766
Allowance for Equity Funds Used During Construction	1,300	855
Interest Expense	(20,793)	(19,239)
INCOME BEFORE INCOME TAX EXPENSE	72,969	116,498
Income Tax Expense	24,111	40,345
NET INCOME	48,858	76,153
Capital Stock Expense	39	39
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 48,819	$ 76,114

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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			(37,500)		(37,500)
Capital Stock Expense		39	(39)		-
TOTAL					1,125,366
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,553				(6,598)	(6,598)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $152				283	283
NET INCOME			76,153		76,153
TOTAL COMPREHENSIVE INCOME					69,838
MARCH 31, 2008	$ 41,026	$ 580,388	$ 598,899	$ (25,109)	$ 1,195,204
DECEMBER 31, 2008	$ 41,026	$ 580,506	$ 674,758	$ (51,025)	$ 1,245,265
Common Stock Dividends			(50,000)		(50,000)
Capital Stock Expense		39	(39)		-
TOTAL					1,195,265
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $340				631	631
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $298				554	554
NET INCOME			48,858		48,858
TOTAL COMPREHENSIVE INCOME					50,043
MARCH 31, 2009	$ 41,026	$ 580,545	$ 673,577	$ (49,840)	$ 1,245,308

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
March 31, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,287	$ 1,063
Other Cash Deposits	21,207	32,300
Accounts Receivable:		
Customers	47,321	56,008
Affiliated Companies	14,651	44,235
Accrued Unbilled Revenues	11,795	18,359
Miscellaneous	13,216	11,546
Allowance for Uncollectible Accounts	(3,075)	(2,895)
Total Accounts Receivable	83,908	127,253
Fuel	60,690	42,075
Materials and Supplies	35,020	33,781
Emission Allowances	18,042	20,211
Risk Management Assets	39,587	35,984
Margin Deposits	21,098	13,613
Prepayments and Other	29,445	27,880
TOTAL	310,284	334,160
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,343,392	2,326,056
Transmission	577,746	574,018
Distribution	1,651,218	1,625,000
Other	208,511	211,088
Construction Work in Progress	406,619	394,918
Total	5,187,486	5,131,080
Accumulated Depreciation and Amortization	1,802,510	1,781,866
TOTAL - NET	3,384,976	3,349,214
OTHER NONCURRENT ASSETS		
Regulatory Assets	314,200	298,357
Long-term Risk Management Assets	34,308	28,461
Deferred Charges and Other	109,452	125,814
TOTAL	457,960	452,632
TOTAL ASSETS	$ 4,153,220	$ 4,136,006

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
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	**(in thousands)**	
Advances from Affiliates	$ 177,736	$ 74,865
Accounts Payable:		
General	121,022	131,417
Affiliated Companies	53,594	120,420
Long-term Debt Due Within One Year – Affiliated	100,000	-
Risk Management Liabilities	20,561	16,490
Customer Deposits	31,724	30,145
Accrued Taxes	141,470	185,293
Other	82,399	82,678
TOTAL	728,506	641,308
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,343,696	1,343,594
Long-term Debt – Affiliated	-	100,000
Long-term Risk Management Liabilities	15,923	14,774
Deferred Income Taxes	457,433	435,773
Regulatory Liabilities and Deferred Investment Tax Credits	164,955	161,102
Employee Benefits and Pension Obligations	146,009	148,123
Deferred Credits and Other	51,390	46,067
TOTAL	2,179,406	2,249,433
TOTAL LIABILITIES	2,907,912	2,890,741
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	580,545	580,506
Retained Earnings	673,577	674,758
Accumulated Other Comprehensive Income (Loss)	(49,840)	(51,025)
TOTAL	1,245,308	1,245,265
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 4,153,220	$ 4,136,006

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 48,858	$ 76,153
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	34,945	48,602
Deferred Income Taxes	38,945	872
Allowance for Equity Funds Used During Construction	(1,300)	(855)
Mark-to-Market of Risk Management Contracts	(3,204)	(1,499)
Deferred Property Taxes	22,262	21,728
Fuel Over/Under-Recovery, Net	(16,934)	-
Change in Other Noncurrent Assets	(8,551)	(11,440)
Change in Other Noncurrent Liabilities	13,410	1,292
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	43,345	(3,383)
Fuel, Materials and Supplies	(19,854)	6,485
Accounts Payable	(81,080)	(6,756)
Accrued Taxes, Net	(57,623)	(2,001)
Other Current Assets	1,157	(2,211)
Other Current Liabilities	(9,817)	(20,972)
Net Cash Flows from Operating Activities	4,559	106,015
INVESTING ACTIVITIES		
Construction Expenditures	(67,831)	(84,513)
Change in Other Cash Deposits	11,093	-
Proceeds from Sales of Assets	206	150
Net Cash Flows Used for Investing Activities	(56,532)	(84,363)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	102,871	68,800
Retirement of Long-term Debt – Nonaffiliated	-	(52,000)
Principal Payments for Capital Lease Obligations	(674)	(725)
Dividends Paid on Common Stock	(50,000)	(37,500)
Net Cash Flows from (Used for) Financing Activities	52,197	(21,425)
Net Increase in Cash and Cash Equivalents	224	227
Cash and Cash Equivalents at Beginning of Period	1,063	1,389
Cash and Cash Equivalents at End of Period	$ 1,287	$ 1,616
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 31,229	$ 24,351
Net Cash Paid for Income Taxes	387	2,494
Noncash Acquisitions Under Capital Leases	254	355
Construction Expenditures Included in Accounts Payable at March 31,	51,297	48,392

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

First Quarter of 2009 Compared to First Quarter of 2008

Reconciliation of First Quarter of 2008 to First Quarter of 2009
Net Income
(in millions)

First Quarter of 2008		$ 55
Changes in Gross Margin:		
Retail Margins	(3)	
FERC Municipals and Cooperatives	(1)	
Off-system Sales	(27)	
Transmission Revenues	(1)	
Other	56	
Total Change in Gross Margin		24
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	16	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	(1)	
Other Income	2	
Interest Expense	(4)	
Total Change in Operating Expenses and Other		12
Income Tax Expense		(10)
First Quarter of 2009		$ 81

Net Income increased $26 million to $81 million in 2009. The key drivers of the increase were a $24 million increase in Gross Margin and a $12 million decrease in Operating Expenses and Other, partially offset by a $10 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 $3 million primarily due to a $14 million decline in industrial margins due to a 21% decrease in industrial sales, partially offset by a $9 million increase in capacity revenue reflecting MLR changes.
- Margins from Off-system Sales decreased $27 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices.
- Other Revenues increased $56 million primarily due to Cook Plant accidental outage insurance policy proceeds of $54 million. Of these insurance proceeds, $20 million were used to offset fuel costs associated with the Cook Plant Unit 1 shutdown which are primarily included in Retail Margins. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

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

- Other Operation and Maintenance expenses decreased $16 million primarily due to lower nuclear and coal production, transmission and distribution costs and deferral of NSR and OPEB costs included in the rate settlement for recovery. See "Indiana Base Rate Filing" section of Note 3.
- Interest Expense increased $4 million primarily due to increased borrowings. In January 2009, I&M issued $475 million of 7% senior unsecured notes.
- Income Tax Expense increased $10 million primarily due to an increase in pretax book income.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

I&M maintains property insurance through NEIL with a $1 million deductible. As of March 31, 2009, I&M recorded $34 million in Prepayments and Other on the Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursements from NEIL for the cost incurred to date to repair the property damage. 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 for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In the first quarter of 2009, I&M recorded $54 million in revenues, including $9 million in revenues that were deferred at December 31, 2008, related to the accidental outage policy. In order to hold customers harmless, in the first quarter of 2009, I&M applied $20 million of the accidental outage insurance proceeds to reduce fuel underrecoveries reflecting recoverable fuel costs as if Unit 1 were operating. 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 2008 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 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 $4.5 million.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 421,927	$ 431,592
Sales to AEP Affiliates	59,986	76,512
Other – Affiliated	30,740	23,219
Other – Nonaffiliated	54,391	5,826
TOTAL	567,044	537,149
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	102,960	101,241
Purchased Electricity for Resale	38,361	21,483
Purchased Electricity from AEP Affiliates	79,978	92,641
Other Operation	109,460	120,366
Maintenance	46,274	51,221
Depreciation and Amortization	32,745	31,722
Taxes Other Than Income Taxes	20,696	19,902
TOTAL	430,474	438,576
OPERATING INCOME	136,570	98,573
Other Income (Expense):		
Interest Income	2,543	829
Allowance for Equity Funds Used During Construction	1,555	880
Interest Expense	(23,531)	(19,202)
INCOME BEFORE INCOME TAX EXPENSE	117,137	81,080
Income Tax Expense	36,185	25,822
NET INCOME	80,952	55,258
Preferred Stock Dividend Requirements	85	85
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 80,867	$ 55,173

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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			(18,750)		(18,750)
Preferred Stock Dividends			(85)		(85)
TOTAL					1,365,466
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,208				(5,958)	(5,958)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $59				110	110
NET INCOME			55,258		55,258
TOTAL COMPREHENSIVE INCOME					49,410
MARCH 31, 2008	$ 56,584	$ 861,291	$ 518,524	$ (21,523)	$ 1,414,876
DECEMBER 31, 2008	$ 56,584	$ 861,291	$ 538,637	$ (21,694)	$ 1,434,818
Common Stock Dividends			(24,500)		(24,500)
Preferred Stock Dividends			(85)		(85)
Gain on Reacquired Preferred Stock		1			1
TOTAL					1,410,234
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $463				859	859
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $111				207	207
NET INCOME			80,952		80,952
TOTAL COMPREHENSIVE INCOME					82,018
MARCH 31, 2009	$ 56,584	$ 861,292	$ 595,004	$ (20,628)	$ 1,492,252

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
March 31, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 983	$ 728
Accounts Receivable:		
Customers	53,502	70,432
Affiliated Companies	76,951	94,205
Accrued Unbilled Revenues	17,943	19,260
Miscellaneous	2,100	1,010
Allowance for Uncollectible Accounts	(3,398)	(3,310)
Total Accounts Receivable	147,098	181,597
Fuel	67,036	67,138
Materials and Supplies	152,782	150,644
Risk Management Assets	38,758	35,012
Regulatory Asset for Under-Recovered Fuel Costs	37,649	33,066
Prepayments and Other	85,958	66,733
TOTAL	530,264	534,918
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,553,486	3,534,188
Transmission	1,123,849	1,115,762
Distribution	1,320,568	1,297,482
Other (including nuclear fuel and coal mining)	746,035	703,287
Construction Work in Progress	255,864	249,020
Total	6,999,802	6,899,739
Accumulated Depreciation, Depletion and Amortization	3,043,645	3,019,206
TOTAL - NET	3,956,157	3,880,533
OTHER NONCURRENT ASSETS		
Regulatory Assets	477,402	455,132
Spent Nuclear Fuel and Decommissioning Trusts	1,206,544	1,259,533
Long-term Risk Management Assets	33,282	27,616
Deferred Charges and Other	108,722	86,193
TOTAL	1,825,950	1,828,474
TOTAL ASSETS	$ 6,312,371	$ 6,243,925

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
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 16,421	$ 476,036
Accounts Payable:		
General	149,538	194,211
Affiliated Companies	52,450	117,589
Long-term Debt Due Within One Year – Affiliated	25,000	-
Risk Management Liabilities	20,101	16,079
Customer Deposits	28,161	26,809
Accrued Taxes	82,522	66,363
Obligations Under Capital Leases	26,410	43,512
Other	110,942	141,160
TOTAL	511,545	1,081,759
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,949,877	1,377,914
Long-term Risk Management Liabilities	15,440	14,311
Deferred Income Taxes	480,091	412,264
Regulatory Liabilities and Deferred Investment Tax Credits	587,787	656,396
Asset Retirement Obligations	914,806	902,920
Deferred Credits and Other	352,496	355,463
TOTAL	4,300,497	3,719,268
TOTAL LIABILITIES	4,812,042	4,801,027
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,077	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	861,292	861,291
Retained Earnings	595,004	538,637
Accumulated Other Comprehensive Income (Loss)	(20,628)	(21,694)
TOTAL	1,492,252	1,434,818
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,312,371	$ 6,243,925

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 80,952	$ 55,258
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	32,745	31,722
Deferred Income Taxes	56,889	5,191
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(7,851)	(881)
Allowance for Equity Funds Used During Construction	(1,555)	(880)
Mark-to-Market of Risk Management Contracts	(3,272)	(1,308)
Amortization of Nuclear Fuel	13,228	21,619
Change in Other Noncurrent Assets	(12,585)	(10,754)
Change in Other Noncurrent Liabilities	9,715	14,234
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	34,499	27,467
Fuel, Materials and Supplies	(2,036)	10,107
Accounts Payable	(68,603)	408
Accrued Taxes, Net	(1,224)	40,026
Other Current Assets	(23,110)	(6,718)
Other Current Liabilities	(27,859)	(21,534)
Net Cash Flows from Operating Activities	79,933	163,957
INVESTING ACTIVITIES		
Construction Expenditures	(92,814)	(67,945)
Purchases of Investment Securities	(178,407)	(132,311)
Sales of Investment Securities	158,086	113,951
Acquisitions of Nuclear Fuel	(75,670)	(98,385)
Proceeds from Sales of Assets and Other	10,757	2,815
Net Cash Flows Used for Investing Activities	(178,048)	(181,875)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	567,949	-
Issuance of Long-term Debt – Affiliated	25,000	-
Change in Advances from Affiliates, Net	(459,615)	140,874
Retirement of Long-term Debt – Nonaffiliated	-	(95,000)
Retirement of Cumulative Preferred Stock	(2)	-
Principal Payments for Capital Lease Obligations	(10,377)	(8,529)
Dividends Paid on Common Stock	(24,500)	(18,750)
Dividends Paid on Cumulative Preferred Stock	(85)	(85)
Net Cash Flows from Financing Activities	98,370	18,510
Net Increase in Cash and Cash Equivalents	255	592
Cash and Cash Equivalents at Beginning of Period	728	1,139
Cash and Cash Equivalents at End of Period	$ 983	$ 1,731
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 35,231	$ 20,216
Net Cash Received for Income Taxes	(355)	(1,118)
Noncash Acquisitions Under Capital Leases	705	2,023
Construction Expenditures Included in Accounts Payable at March 31,	29,910	16,280
Acquisition of Nuclear Fuel Included in Accounts Payable at March 31,	17,016	-

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

First Quarter of 2009 Compared to First Quarter of 2008

Reconciliation of First Quarter of 2008 to First Quarter of 2009
Net Income
(in millions)

First Quarter of 2008		$ 138
Changes in Gross Margin:		
Retail Margins	(37)	
Off-system Sales	(29)	
Other	10	
Total Change in Gross Margin		(56)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(21)	
Depreciation and Amortization	(15)	
Carrying Costs Income	(2)	
Other Income	(2)	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		(45)
Income Tax Expense		36
First Quarter of 2009		$ 73

Net Income decreased $65 million to $73 million in 2009. The key drivers of the decrease were a $56 million decrease in Gross Margin and a $45 million increase in Operating Expenses and Other offset by a $36 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 $37 million primarily due to the following:
  - A $58 million decrease in fuel expense related to a coal contract amendment recorded in 2008 which reduced future deliveries to OPCo in exchange for consideration received.
  - A $6 million decrease in retail and wholesale sales driven by lower industrial usage.

  These decreases were partially offset by:
  - A $1 million increase in fuel margins due to the deferral of fuel costs in 2009. The PUCO's March 2009 approval of OPCo's ESP allows for the recovery of fuel and related costs beginning January 1, 2009. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $9 million increase in capacity settlements under the Interconnection Agreement.
  - An $8 million increase related to new rates implemented due to the accrual for March unbilled revenues at higher rates set by the Ohio ESP.
- Margins from Off-system Sales decreased $29 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.
- Other revenues increased $10 million primarily due to increased gains on sales of emission allowances. Due to the implementation of OPCo's ESP as discussed above, emission gains and losses incurred after January 1, 2009 will be included in OPCo's fuel adjustment clause.

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

- Other Operation and Maintenance expenses increased $21 million primarily due to:
  - An $8 million increase related to an obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of OPCo's ESP. See "Ohio Electric Security Plan Filings" section of Note 3.
  - An $8 million increase in recoverable PJM expenses.
  - A $7 million increase in maintenance of overhead lines primarily due to ice and wind storm costs incurred in January and February 2009.
  - A $4 million increase in maintenance expenses from planned and forced outages at various plants.

  These increases were partially offset by:
  - A $7 million decrease in employee-related expenses.
- Depreciation and Amortization increased $15 million primarily due to:
  - A $19 million increase from higher depreciable property balances as a result of environmental improvements placed in service and various other property additions and higher depreciation rates related to shortened depreciable lives for certain generating facilities.
  - A $2 million increase as a result of the completion of the amortization of a regulated liability in December 2008 related to energy sales to Ormet at below market rates. See "Ormet" section of Note 3.

  These increases were partially offset by:
  - A $7 million decrease due to the completion of the amortization of regulatory assets in December 2008.
- Income Tax Expense decreased $36 million primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

OPCo's credit ratings as of March 31, 2009 were as follows:

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

S&P and Fitch have OPCo on stable outlook while Moody's has OPCo on negative outlook. In January 2009, Moody's placed OPCo on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries. If OPCo receives a downgrade from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the three months ended March 31, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 12,679	$ 6,666
Cash Flows from (Used for):		
Operating Activities	(22,900)	150,065
Investing Activities	(156,584)	(140,253)
Financing Activities	180,174	(12,861)
Net Increase (Decrease) in Cash and Cash Equivalents	690	(3,049)
Cash and Cash Equivalents at End of Period	$ 13,369	$ 3,617

Operating Activities

Net Cash Flows Used for Operating Activities were $23 million in 2009. OPCo produced income of $73 million during the period and a noncash expense item of $84 million for Depreciation and Amortization, $72 million for Deferred Income Taxes and $65 million for Fuel Over/Under-Recovery due to an under-recovery of fuel costs in Ohio. 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 primarily relates to a number of items. Accounts Payable had a $95 million cash outflow primarily due to OPCo's provision for revenue refund of $62 million which was paid in the first quarter 2009 to the AEP West companies as part of the FERC's recent order on the SIA. Accrued Taxes, Net had a $79 million cash outflow due to a decrease of federal income tax related accruals and temporary timing differences of payments for property taxes. Fuel, Materials and Supplies had a $53 million cash outflow primarily due to an increase in coal inventory. Accounts Receivable, Net had a $40 million inflow due to timing differences of payments from customers and the receipt of final payment due to a coal contract amendment.

Net Cash Flows from Operating Activities were $150 million in 2008. OPCo produced Net Income of $138 million during the period and a noncash expense item of $69 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 current period activity in working capital relates to Accounts Receivable, Net. Accounts Receivable, Net had a $22 million outflow primarily due to a coal contract amendment in January 2008.

Investing Activities

Net Cash Used for Investing Activities were $157 million and $140 million in 2009 and 2008, respectively. Construction Expenditures were $163 million and $142 million in 2009 and 2008, 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 the flue gas desulfurization projects at the Cardinal, Amos and Mitchell plants. OPCo forecasts approximately $439 million of construction expenditures for all of 2009, excluding AFUDC.

Financing Activities

Net Cash Flows from Financing Activities were $180 million in 2009 primarily due to a net increase of $186 million in borrowings from the Utility Money Pool.

Net Cash Flows Used for Financing Activities were $13 million in 2008 primarily due to a net decrease of $14 million in borrowings from the Utility Money Pool.

Financing Activity

Long-term debt issuances and principal payments made during the first three months of 2009 were:

<u>Issuances</u>

None

<u>Principal Payments</u>

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable – Nonaffiliated	$ 3,500	7.21	2009
Notes Payable – Nonaffiliated	1,000	6.27	2009

Liquidity

The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact OPCo's access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications on OPCo since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on OPCo's operations and ability to issue debt at reasonable interest rates.

OPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. OPCo has $78 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.

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

Summary Obligation Information

A summary of contractual obligations is included in the 2008 Annual Report and has not changed significantly from year-end.

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 2008 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 2008 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 March 31, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet March 31, 2009 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 65,411	$ 5,646	$ -	$ (7,697)	$ 63,360
Noncurrent Assets	54,262	156	-	(8,753)	45,665
Total MTM Derivative Contract Assets	119,673	5,802	-	(16,450)	109,025
Current Liabilities	(40,578)	(1,268)	(1,772)	7,723	(35,895)
Noncurrent Liabilities	(39,704)	(27)	(1,203)	15,939	(24,995)
Total MTM Derivative Contract Liabilities	(80,282)	(1,295)	(2,975)	23,662	(60,890)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 39,391	$ 4,507	$ (2,975)	$ 7,212	$ 48,135

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$	37,761
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(4,634)
Fair Value of New Contracts at Inception When Entered During the Period (a)		1,153
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		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		4,165
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		946
Total MTM Risk Management Contract Net Assets		39,391
Cash Flow Hedge Contracts		4,507
DETM Assignment (d)		(2,975)
Collateral Deposits		7,212
Ending Net Risk Management Assets at March 31, 2009	$	48,135

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "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 liabilities/assets.
(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 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 March 31, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (1,193)	$ (31)	$ 1	$ -	$ -	$ -	$ (1,223)
Level 2 (b)	15,214	6,549	3,357	(342)	26	-	24,804
Level 3 (c)	3,633	1,826	1,103	1,096	144	-	7,802
Total	17,654	8,344	4,461	754	170	-	31,383
Dedesignated Risk Management Contracts (d)	2,456	3,195	1,244	1,113	-	-	8,008
Total MTM Risk Management Contract Net Assets	$ 20,110	$ 11,539	$ 5,705	$ 1,867	$ 170	$ -	$ 39,391

(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 contracts.

Credit Risk

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

See Note 7 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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 March 31, 2009, a near term typical change in commodity prices is not expected to have a material effect on 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:

Three Months Ended March 31, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$247	$439	$238	$113	$140	$1,284	$411	$131

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 OPCo's exposure to extreme price moves. Management employs a historical-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 translated into the largest potential MTM 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 $12 million.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 524,686	$ 555,478
Sales to AEP Affiliates	226,694	236,848
Other - Affiliated	7,488	5,299
Other - Nonaffiliated	3,847	4,563
TOTAL	762,715	802,188
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	253,474	238,934
Purchased Electricity for Resale	52,269	34,577
Purchased Electricity from AEP Affiliates	16,742	32,516
Other Operation	99,598	89,882
Maintenance	60,040	48,697
Depreciation and Amortization	84,023	68,566
Taxes Other Than Income Taxes	51,492	51,578
TOTAL	617,638	564,750
OPERATING INCOME	145,077	237,438
Other Income (Expense):		
Interest Income	244	2,908
Carrying Costs Income	1,584	4,229
Allowance for Equity Funds Used During Construction	867	544
Interest Expense	(38,681)	(33,919)
INCOME BEFORE INCOME TAX EXPENSE	109,091	211,200
Income Tax Expense	36,482	72,910
NET INCOME	72,609	138,290
Less: Net Income Attributable to Noncontrolling Interest	463	463
NET INCOME ATTRIBUTABLE TO OPCo SHAREHOLDERS	72,146	137,827
Less: Preferred Stock Dividend Requirements	183	183
EARNINGS ATTRIBUTABLE TO OPCo COMMON SHAREHOLDER	$ 71,963	$ 137,644

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 EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	OPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
DECEMBER 31, 2007	$ 321,201	$ 536,640	$ 1,469,717	$ (36,541)	$ 15,923	$ 2,306,940
EITF 06-10 Adoption, Net of Tax of $1,004			(1,864)			(1,864)
SFAS 157 Adoption, Net of Tax of $152			(282)			(282)
Common Stock Dividends – Nonaffiliated					(463)	(463)
Preferred Stock Dividends			(183)			(183)
Other					2,015	2,015
TOTAL						2,306,163
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of $4,745				(8,811)		(8,811)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $379				703		703
NET INCOME			137,827		463	138,290
TOTAL COMPREHENSIVE INCOME						130,182
MARCH 31, 2008	$ 321,201	$ 536,640	$ 1,605,215	$ (44,649)	$ 17,938	$ 2,436,345
DECEMBER 31, 2008	$ 321,201	$ 536,640	$ 1,697,962	$ (133,858)	$ 16,799	$ 2,438,744
Common Stock Dividends – Nonaffiliated					(463)	(463)
Preferred Stock Dividends			(183)			(183)
Other					1,111	1,111
TOTAL						2,439,209
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $570				1,058		1,058
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $855				1,588		1,588
NET INCOME			72,146		463	72,609
TOTAL COMPREHENSIVE INCOME						75,255
MARCH 31, 2009	$ 321,201	$ 536,640	$ 1,769,925	$ (131,212)	$ 17,910	$ 2,514,464

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

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 13,369	$ 12,679
Accounts Receivable:		
Customers	76,210	91,235
Affiliated Companies	99,508	118,721
Accrued Unbilled Revenues	22,658	18,239
Miscellaneous	12,797	23,393
Allowance for Uncollectible Accounts	(3,630)	(3,586)
Total Accounts Receivable	207,543	248,002
Fuel	238,012	186,904
Materials and Supplies	108,899	107,419
Risk Management Assets	63,360	53,292
Accrued Tax Benefits	51,287	13,568
Prepayments and Other	40,101	42,999
TOTAL	722,571	664,863
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	6,589,421	6,025,277
Transmission	1,128,310	1,111,637
Distribution	1,493,642	1,472,906
Other	390,415	391,862
Construction Work in Progress	270,475	787,180
Total	9,872,263	9,788,862
Accumulated Depreciation and Amortization	3,149,697	3,122,989
TOTAL - NET	6,722,566	6,665,873
OTHER NONCURRENT ASSETS		
Regulatory Assets	510,585	449,216
Long-term Risk Management Assets	45,665	39,097
Deferred Charges and Other	160,171	184,777
TOTAL	716,421	673,090
TOTAL ASSETS	$ 8,161,558	$ 8,003,826

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 EQUITY
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 320,166	$ 133,887
Accounts Payable:		
General	188,516	193,675
Affiliated Companies	99,427	206,984
Long-term Debt Due Within One Year – Nonaffiliated	73,000	77,500
Risk Management Liabilities	35,895	29,218
Customer Deposits	26,406	24,333
Accrued Taxes	146,442	187,256
Accrued Interest	35,934	44,245
Other	166,113	163,702
TOTAL	1,091,899	1,060,800
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,762,039	2,761,876
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	24,995	23,817
Deferred Income Taxes	971,014	927,072
Regulatory Liabilities and Deferred Investment Tax Credits	127,916	127,788
Employee Benefits and Pension Obligations	284,918	288,106
Deferred Credits and Other	167,686	158,996
TOTAL	4,538,568	4,487,655
TOTAL LIABILITIES	5,630,467	5,548,455
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,627	16,627
Commitments and Contingencies (Note 4)		
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	1,769,925	1,697,962
Accumulated Other Comprehensive Income (Loss)	(131,212)	(133,858)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,496,554	2,421,945
Noncontrolling Interest	17,910	16,799
TOTAL EQUITY	2,514,464	2,438,744
TOTAL LIABILITIES AND EQUITY	$ 8,161,558	$ 8,003,826

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 72,609	$ 138,290
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	84,023	68,566
Deferred Income Taxes	71,740	10,850
Carrying Costs Income	(1,584)	(4,229)
Allowance for Equity Funds Used During Construction	(867)	(544)
Mark-to-Market of Risk Management Contracts	(7,117)	(5,035)
Deferred Property Taxes	21,527	20,574
Fuel Over/Under-Recovery, Net	(65,192)	-
Change in Other Noncurrent Assets	1,669	(46,438)
Change in Other Noncurrent Liabilities	19,318	5,397
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	39,518	(21,586)
Fuel, Materials and Supplies	(52,588)	(4,130)
Accounts Payable	(95,306)	9,005
Customer Deposits	2,073	69
Accrued Taxes, Net	(78,533)	15,790
Accrued Interest	(8,311)	(4,348)
Other Current Assets	(15,394)	(13,020)
Other Current Liabilities	(10,485)	(19,146)
Net Cash Flows from (Used for) Operating Activities	(22,900)	150,065
INVESTING ACTIVITIES		
Construction Expenditures	(163,263)	(142,257)
Proceeds from Sales of Assets	2,796	2,004
Other	3,883	-
Net Cash Flows Used for Investing Activities	(156,584)	(140,253)
FINANCING ACTIVITIES		
Change in Short-term Debt, Net – Nonaffiliated	-	(701)
Change in Advances from Affiliates, Net	186,279	(14,140)
Retirement of Long-term Debt – Nonaffiliated	(4,500)	(7,463)
Funds from Amended Coal Contact	-	10,000
Principal Payments for Capital Lease Obligations	(1,316)	(1,926)
Dividends Paid on Common Stock – Nonaffiliated	(463)	(463)
Dividends Paid on Cumulative Preferred Stock	(183)	(183)
Other	357	2,015
Net Cash Flows from (Used for) Financing Activities	180,174	(12,861)
Net Increase (Decrease) in Cash and Cash Equivalents	690	(3,049)
Cash and Cash Equivalents at Beginning of Period	12,679	6,666
Cash and Cash Equivalents at End of Period	$ 13,369	$ 3,617
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 64,554	$ 37,491
Net Cash Paid for Income Taxes	2,337	10,850
Noncash Acquisitions Under Capital Leases	157	687
Noncash Acquisition of Coal Land Rights	-	41,600
Construction Expenditures Included in Accounts Payable at March 31,	15,767	21,828

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

First Quarter of 2009 Compared to First Quarter of 2008

Reconciliation of First Quarter of 2008 to First Quarter of 2009
Net Income
(in millions)

First Quarter of 2008		$	37
Changes in Gross Margin:			
Retail and Off-system Sales Margins	17		
Transmission Revenues	1		
Other	(9)		
Total Change in Gross Margin			9
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	26		
Deferral of Ice Storm Costs	(80)		
Depreciation and Amortization	(2)		
Other Income	(1)		
Total Change in Operating Expenses and Other			(57)
Income Tax Expense			17
First Quarter of 2009		$	6

Net Income decreased $31 million to $6 million in 2009. The key drivers of the decrease were a $57 million increase in Operating Expenses and Other, partially offset by a $17 million decrease in Income Tax Expense and a $9 million increase in Gross Margin.

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 $17 million primarily due to an increase in retail sales margins resulting from base rate adjustments during the year.
- Other revenues decreased $9 million primarily due to the recognition of the sale of SO_2 allowances in 2008.

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

- Other Operation and Maintenance expenses decreased $26 million primarily due to:
  - A $10 million decrease primarily due to a write-off in 2008 of pre-construction costs related to the cancelled Red Rock Generating Facility.
  - A $6 million decrease due to the deferral of generation maintenance expenses as a result of PSO's base rate filing. See "2008 Oklahoma Base Rate Filing" section of Note 3.
  - A $4 million decrease in amortization of deferred ice storm costs.
  - A $4 million decrease in employee-related expenses.
- Deferral of Ice Storm Costs in 2008 of $80 million results from an OCC order approving recovery of ice storm expenses related to storms in January and December 2007.
- Depreciation and Amortization expenses increased $2 million primarily due to the amortization of regulatory assets related to the Generation Cost Recovery Rider. See "2008 Oklahoma Base Rate Filing" section of Note 3.
- Income Tax Expense decreased $17 million primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

PSO's credit ratings as of March 31, 2009 were as follows:

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

S&P and Fitch have PSO on stable outlook. In February 2009, Moody's affirmed its stable rating outlook for PSO. If PSO receives a downgrade from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the three months ended March 31, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,345	$ 1,370
Cash Flows from (Used for):		
Operating Activities	103,803	(39,805)
Investing Activities	(59,145)	(21,853)
Financing Activities	(44,726)	61,723
Net Increase (Decrease) in Cash and Cash Equivalents	(68)	65
Cash and Cash Equivalents at End of Period	$ 1,277	$ 1,435

Operating Activities

Net Cash Flows from Operating Activities were $104 million in 2009. PSO produced Net Income of $6 million during the period and had noncash expense item of $28 million for Depreciation and Amortization offset by a $28 million increase in Deferred Property Taxes and a $14 million increase in 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 $93 million inflow from Accounts Receivable, Net was primarily due to receiving the SIA refund from the AEP East companies and lower customer receivables. The $37 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes. The $37 million inflow from Fuel Over/Under-Recovery, Net was primarily due to lower fuel costs. The $29 million outflow from Accounts Payable was primarily due to timing differences for payments to affiliates and payment of items accrued at December 31, 2008.

Net Cash Flows Used for Operating Activities were $40 million in 2008. PSO produced Net Income of $37 million during the period and had noncash expense items of $26 million for Depreciation and Amortization and $38 million for Deferred Income Taxes offset by a $27 million increase in Deferred Property Taxes. PSO established an $80 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 current period activity in working capital relates to Accounts Payable. Accounts Payable had a $26 million outflow primarily due to payments for ice storm costs accrued at December 31, 2007 offset by an increase in accruals related to fuel.

Investing Activities

Net Cash Flows Used for Investing Activities during 2009 and 2008 were $59 million and $22 million, respectively. Construction Expenditures of $52 million and $73 million in 2009 and 2008, 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 investments in the Utility Money Pool. PSO forecasts approximately $188 million of construction expenditures for all of 2009, excluding AFUDC.

Financing Activities

Net Cash Flows Used for Financing Activities were $45 million during 2009. PSO had a net decrease of $70 million in borrowings from the Utility Money Pool. PSO issued $34 million of Pollution Control Bonds in February 2009. In addition, PSO paid $7 million in dividends on common stock.

Net Cash Flows from Financing Activities were $62 million during 2008. PSO had a net increase of $62 million in borrowings from the Utility Money Pool.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2009 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$ 33,700	5.25	2014

Retirements

None

Liquidity

The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact PSO's access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications on PSO since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on PSO's operations and ability to issue debt at reasonable interest rates.

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 June 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.

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

Summary Obligation Information

A summary of contractual obligations is included in the 2008 Annual Report and has not changed significantly from year-end other than the debt issuances discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

New Generation/Purchased Power Agreement

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

2008 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 2008 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 March 31, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheet
March 31, 2009
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 7,632	$ -	$ -	$ -	$ 7,632
Noncurrent Assets	600	-	-	-	600
Total MTM Derivative Contract Assets	8,232	-	-	-	8,232
Current Liabilities	(5,967)	(33)	(100)	393	(5,707)
Noncurrent Liabilities	(312)	-	(68)	-	(380)
Total MTM Derivative Contract Liabilities	(6,279)	(33)	(168)	393	(6,087)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,953	$ (33)	$ (168)	$ 393	$ 2,145

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$	1,660
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		117
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		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		6
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		170
Total MTM Risk Management Contract Net Assets		1,953
Cash Flow Hedge Contracts		(33)
DETM Assignment (d)		(168)
Collateral Deposits		393
Ending Net Risk Management Assets at March 31, 2009	$	2,145

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.

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

(c) "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 liabilities/assets.

(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 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 March 31, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (439)	$ (1)	$ -	$ -	$ -	$ -	$ (440)
Level 2 (b)	1,605	1,064	(267)	(10)	-	-	2,392
Level 3 (c)	-	1	-	-	-	-	1
Total	$ 1,166	$ 1,064	$ (267)	$ (10)	$ -	$ -	$ 1,953

(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.

Credit Risk

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

See Note 7 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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 March 31, 2009, 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:

Three Months Ended March 31, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$14	$34	$13	$4	$4	$164	$44	$6

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 historical-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 translated into the largest potential MTM 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 $909 thousand.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 278,771	$ 318,880
Sales to AEP Affiliates	15,823	15,935
Other	693	1,185
TOTAL	295,287	336,000
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	119,399	153,205
Purchased Electricity for Resale	44,425	48,582
Purchased Electricity from AEP Affiliates	5,915	17,269
Other Operation	39,545	55,999
Maintenance	25,430	34,587
Deferral of Ice Storm Costs	-	(79,902)
Depreciation and Amortization	27,950	26,167
Taxes Other Than Income Taxes	10,751	10,952
TOTAL	273,415	266,859
OPERATING INCOME	21,872	69,141
Other Income (Expense):		
Interest Income	648	1,128
Carrying Costs Income	1,711	1,634
Allowance for Equity Funds Used During Construction	170	1,359
Interest Expense	(14,805)	(14,941)
INCOME BEFORE INCOME TAX EXPENSE	9,596	58,321
Income Tax Expense	3,558	20,922
NET INCOME	6,038	37,399
Preferred Stock Dividend Requirements	53	53
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 5,985	$ 37,346

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive (Loss)	Total
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)
Preferred Stock Dividends			(53)		(53)
TOTAL					639,738
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $24				45	45
NET INCOME			37,399		37,399
TOTAL COMPREHENSIVE INCOME					37,444
MARCH 31, 2008	$ 157,230	$ 310,016	$ 210,778	$ (842)	$ 677,182
DECEMBER 31, 2008	$ 157,230	$ 340,016	$ 251,704	$ (704)	$ 748,246
Common Stock Dividends			(7,250)		(7,250)
Preferred Stock Dividends			(53)		(53)
Other		4,214	(4,214)		-
TOTAL					740,943
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $12				22	22
NET INCOME			6,038		6,038
TOTAL COMPREHENSIVE INCOME					6,060
MARCH 31, 2009	$ 157,230	$ 344,230	$ 246,225	$ (682)	$ 747,003

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,277	$ 1,345
Advances to Affiliates	7,009	-
Accounts Receivable:		
Customers	29,010	39,823
Affiliated Companies	60,513	138,665
Miscellaneous	4,955	8,441
Allowance for Uncollectible Accounts	(130)	(20)
Total Accounts Receivable	94,348	186,909
Fuel	24,739	27,060
Materials and Supplies	44,982	44,047
Risk Management Assets	7,632	5,830
Deferred Tax Benefits	33,624	9,123
Accrued Tax Benefits	-	3,876
Prepayments and Other	6,607	3,371
TOTAL	220,218	281,561
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,273,326	1,266,716
Transmission	628,733	622,665
Distribution	1,493,418	1,468,481
Other	248,238	248,897
Construction Work in Progress	83,239	85,252
Total	3,726,954	3,692,011
Accumulated Depreciation and Amortization	1,204,894	1,192,130
TOTAL - NET	2,522,060	2,499,881
OTHER NONCURRENT ASSETS		
Regulatory Assets	300,305	304,737
Long-term Risk Management Assets	600	917
Deferred Charges and Other	39,088	13,702
TOTAL	339,993	319,356
TOTAL ASSETS	$ 3,082,271	$ 3,100,798

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
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 70,308
Accounts Payable:		
General	68,187	84,121
Affiliated Companies	67,490	86,407
Long-term Debt Due Within One Year – Nonaffiliated	50,000	50,000
Risk Management Liabilities	5,707	4,753
Customer Deposits	41,967	40,528
Accrued Taxes	51,818	19,000
Regulatory Liability for Over-Recovered Fuel Costs	147,199	58,395
Provision for Revenue Refund	-	52,100
Other	39,606	61,194
TOTAL	471,974	526,806
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	868,619	834,859
Long-term Risk Management Liabilities	380	378
Deferred Income Taxes	523,842	514,720
Regulatory Liabilities and Deferred Investment Tax Credits	324,693	323,750
Deferred Credits and Other	140,498	146,777
TOTAL	1,858,032	1,820,484
TOTAL LIABILITIES	2,330,006	2,347,290
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	344,230	340,016
Retained Earnings	246,225	251,704
Accumulated Other Comprehensive Income (Loss)	(682)	(704)
TOTAL	747,003	748,246
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,082,271	$ 3,100,798

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 6,038	$ 37,399
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	27,950	26,167
Deferred Income Taxes	(13,835)	37,899
Deferral of Ice Storm Costs	-	(79,902)
Allowance for Equity Funds Used During Construction	(170)	(1,359)
Mark-to-Market of Risk Management Contracts	(562)	(11,881)
Deferred Property Taxes	(28,050)	(26,694)
Change in Other Noncurrent Assets	(1,282)	22,022
Change in Other Noncurrent Liabilities	(1,879)	(20,541)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	92,561	(5,027)
Fuel, Materials and Supplies	1,386	(5,086)
Accounts Payable	(28,623)	(25,698)
Accrued Taxes, Net	36,694	22,107
Fuel Over/Under-Recovery, Net	36,650	4,572
Other Current Assets	(3,511)	6,976
Other Current Liabilities	(19,564)	(20,759)
Net Cash Flows from (Used for) Operating Activities	103,803	(39,805)
INVESTING ACTIVITIES		
Construction Expenditures	(52,368)	(73,203)
Change in Advances to Affiliates, Net	(7,009)	51,202
Proceeds from Sales of Assets	232	148
Net Cash Flows Used for Investing Activities	(59,145)	(21,853)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	33,283	-
Change in Advances from Affiliates, Net	(70,308)	62,159
Principal Payments for Capital Lease Obligations	(398)	(383)
Dividends Paid on Common Stock	(7,250)	-
Dividends Paid on Cumulative Preferred Stock	(53)	(53)
Net Cash Flows from (Used for) Financing Activities	(44,726)	61,723
Net Increase (Decrease) in Cash and Cash Equivalents	(68)	65
Cash and Cash Equivalents at Beginning of Period	1,345	1,370
Cash and Cash Equivalents at End of Period	$ 1,277	$ 1,435
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 29,174	$ 12,380
Net Cash Paid (Received) for Income Taxes	391	(19,408)
Noncash Acquisitions Under Capital Leases	391	135
Construction Expenditures Included in Accounts Payable at March 31,	11,776	21,086

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

First Quarter of 2009 Compared to First Quarter of 2008

Reconciliation of First Quarter of 2008 to First Quarter of 2009
Net Income
(in millions)

First Quarter of 2008		$ 6
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	(3)	
Transmission Revenues	2	
Other	(2)	
Total Change in Gross Margin		(3)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	10	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	2	
Other Income	3	
Interest Expense	1	
Total Change in Operating Expenses and Other		15
Income Tax Expense		(6)
First Quarter of 2009		$ 12

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

Net Income increased $6 million to $12 million in 2009. The key drivers of the increase were a $15 million decrease in Operating Expenses and Other, partially offset by a $6 million increase in Income Tax Expense and a $3 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 and Off-system Sales Margins decreased $3 million primarily due to a $4 million decrease in retail sales margins primarily related to reduced customer usage, partially offset by increased rates related to the Louisiana Formula Rate Plan.
- Transmission Revenues increased $2 million primarily due to higher rates in the SPP region.
- Other revenues decreased $2 million primarily due to a decrease in revenues from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC to Cleco Corporation, a nonaffiliated entity and decreased gain on sales of emission allowances. The decreased revenue from coal deliveries was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

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

- Other Operation and Maintenance expenses decreased $10 million primarily due to:
  - A $5 million decrease in operation expense as a result of lower employee-related expenses.
  - A $2 million gain on sale of property related to the sale of percentage ownership of Turk Plant to nonaffiliated companies who exercised their participation options.
  - A $2 million decrease in expenses for coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC. The decreased expenses for coal deliveries were partially offset by a corresponding decrease in revenues from mining operations as discussed above.
- Taxes Other Than Income Taxes decreased $2 million primarily due to lower property tax and revenue tax.
- Other Income increased $3 million primarily due to an increase in the AFUDC equity as a result of construction at the Turk Plant and Stall Unit. See Note 3.
- Income Tax Expense increased $6 million primarily due to an increase in pre-tax book income and prior year income tax adjustments.

Financial Condition

Credit Ratings

SWEPCo's credit ratings as of March 31, 2009 were as follows:

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

S&P and Fitch have SWEPCo on stable outlook. In 2009, Moody's placed SWEPCo on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries. If SWEPCo receives a downgrade from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the three months ended March 31, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,910	$ 1,742
Cash Flows from (Used for):		
Operating Activities	93,470	(3,153)
Investing Activities	(103,382)	(125,877)
Financing Activities	9,739	133,191
Net Increase (Decrease) in Cash and Cash Equivalents	(173)	4,161
Cash and Cash Equivalents at End of Period	$ 1,737	$ 5,903

Operating Activities

Net Cash Flows from Operating Activities were $93 million in 2009. SWEPCo produced Net Income of $12 million during the period and had a noncash expense item of $37 million for Depreciation and Amortization, $30 million for Deferred Property Taxes and $27 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 $95 million inflow from Accounts Receivable, Net was primarily due to the receipt of payment for SIA from the AEP East companies. The $59 million inflow from Accrued Taxes, Net was the result of increased accruals related to income and property taxes. The $50 million outflow from Other Current Liabilities was due to a decrease in checks outstanding, a refund to wholesale customers for the SIA and payments of employee-related expenses. The $27 million inflow from Fuel Over/Under-Recovery, Net was the result of a decrease in fuel costs in relation to the recovery of these costs from customers. The $20 million outflow from Accrued Interest was due to increased long-term debt outstanding as well as the timing of interest payments in relation to the accruals for payments.

Net Cash Flows Used for Operating Activities were $3 million in 2008. SWEPCo produced Net Income of $6 million during the period and had a noncash expense item of $36 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 $40 million outflow from Fuel Over/Under-Recovery, Net was the result of higher fuel costs. The $22 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $21 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes.

Investing Activities

Net Cash Flows Used for Investing Activities during 2009 and 2008 were $103 million and $126 million, respectively. Construction Expenditures of $170 million and $125 million in 2009 and 2008, respectively, were primarily related to new generation projects at the Turk Plant and Stall Unit. Proceeds from Sales of Assets in 2009 primarily includes $104 million in progress payments for Turk Plant construction from the joint owners. Change in Advances to Affiliates, Net of $38 million in 2009 was primarily due to the contribution from Parent and net income. SWEPCo forecasts approximately $457 million of construction expenditures for all of 2009, excluding AFUDC.

Financing Activities

Net Cash Flows from Financing Activities were $10 million during 2009. SWEPCo received a Capital Contribution from Parent of $18 million. SWEPCo had a net decrease of $3 million in borrowings from the Utility Money Pool.

Net Cash Flows from Financing Activities were $133 million during 2008. SWEPCo received a Capital Contribution from Parent of $50 million. SWEPCo had a net increase of $88 million in borrowings from the Utility Money Pool.

Financing Activity

Long-term debt issuances and principal payments made during the first three months of 2009 were:

Issuances

None

Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable – Nonaffiliated	$ 1,101	4.47	2011

Liquidity

The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact SWEPCo’s access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications on SWEPCo since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on SWEPCo’s operations and ability to issue debt at reasonable interest rates.

SWEPCo participates in the Utility Money Pool, which provides access to AEP’s liquidity. SWEPCo will rely upon cash flows from operations and access to the Utility Money Pool to fund its current operations and capital expenditures.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of liquidity.

Summary Obligation Information

A summary of contractual obligations is included in the 2008 Annual Report and has not changed significantly from year-end.

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 if 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 2008 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 2008 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 March 31, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

**Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
March 31, 2009
(in thousands)**

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 10,187	$ -	$ -	$ -	$ 10,187
Noncurrent Assets	919	1	-	-	920
Total MTM Derivative Contract Assets	11,106	1	-	-	11,107
Current Liabilities	(7,572)	(331)	(118)	456	(7,565)
Noncurrent Liabilities	(448)	-	(80)	-	(528)
Total MTM Derivative Contract Liabilities	(8,020)	(331)	(198)	456	(8,093)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,086	$ (330)	$ (198)	$ 456	$ 3,014

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$	2,643
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		263
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		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		85
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		95
Total MTM Risk Management Contract Net Assets		3,086
Cash Flow Hedge Contracts		(330)
DETM Assignment (d)		(198)
Collateral Deposits		456
Ending Net Risk Management Assets at March 31, 2009	$	3,014

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "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 liabilities/assets.
(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 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 March 31, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (518)	$ (1)	$ -	$ -	$ -	$ -	$ (519)
Level 2 (b)	2,340	1,688	(412)	(13)	-	-	3,603
Level 3 (c)	-	2	-	-	-	-	2
Total	$ 1,822	$ 1,689	$ (412)	$ (13)	$ -	$ -	$ 3,086

(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.

Credit Risk

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

See Note 7 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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 March 31, 2009, a near term typical change in commodity prices is not expected to have a material effect on 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:

Three Months Ended March 31, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$23	$49	$20	$6	$8	$220	$62	$8

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 historical-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 translated into the largest potential MTM 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 $3 million.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 302,383	$ 313,913
Sales to AEP Affiliates	8,344	13,592
Lignite Revenues – Nonaffiliated	10,720	11,988
Other	355	300
TOTAL	321,802	339,793
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	126,315	117,661
Purchased Electricity for Resale	24,397	40,270
Purchased Electricity from AEP Affiliates	13,010	20,440
Other Operation	54,204	63,579
Maintenance	26,702	27,468
Depreciation and Amortization	36,792	36,136
Taxes Other Than Income Taxes	15,389	17,419
TOTAL	296,809	322,973
OPERATING INCOME	24,993	16,820
Other Income (Expense):		
Interest Income	454	877
Allowance for Equity Funds Used During Construction	6,405	3,063
Interest Expense	(16,299)	(17,142)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	15,553	3,618
Income Tax Expense (Credit)	3,853	(1,987)
NET INCOME	11,700	5,605
Less: Net Income Attributable to Noncontrolling Interest	1,137	995
NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	10,563	4,610
Less: Preferred Stock Dividend Requirements	57	57
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 10,506	$ 4,553

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
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
DECEMBER 31, 2007	$ 135,660	$ 330,003	$ 523,731	$ (16,439)	$ 1,687	$ 974,642
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		50,000				50,000
Common Stock Dividends – Nonaffiliated					(949)	(949)
Preferred Stock Dividends			(57)			(57)
TOTAL						1,022,490
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of $143				(269)	4	(265)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $127				235		235
NET INCOME			4,610		995	5,605
TOTAL COMPREHENSIVE INCOME						5,575
MARCH 31, 2008	$ 135,660	$ 380,003	$ 527,138	$ (16,473)	$ 1,737	$ 1,028,065
DECEMBER 31, 2008	$ 135,660	$ 530,003	$ 615,110	$ (32,120)	$ 276	$ 1,248,929
Capital Contribution from Parent		17,500				17,500
Common Stock Dividends – Nonaffiliated					(1,115)	(1,115)
Preferred Stock Dividends			(57)			(57)
Other		2,476	(2,476)			-
TOTAL						1,265,257
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $51				95		95
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $243				451		451
NET INCOME			10,563		1,137	11,700
TOTAL COMPREHENSIVE INCOME						12,246
MARCH 31, 2009	$ 135,660	$ 549,979	$ 623,140	$ (31,574)	$ 298	$ 1,277,503

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
March 31, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,737	$ 1,910
Advances to Affiliates	37,649	-
Accounts Receivable:		
Customers	53,346	53,506
Affiliated Companies	29,914	121,928
Miscellaneous	9,590	12,052
Allowance for Uncollectible Accounts	(145)	(135)
Total Accounts Receivable	92,705	187,351
Fuel	103,544	100,018
Materials and Supplies	50,973	49,724
Risk Management Assets	10,187	8,185
Regulatory Asset for Under-Recovered Fuel Costs	35,495	75,006
Prepayments and Other	23,420	20,147
TOTAL	355,710	442,341
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,811,359	1,808,482
Transmission	793,702	786,731
Distribution	1,415,210	1,400,952
Other	712,739	711,260
Construction Work in Progress	904,837	869,103
Total	5,637,847	5,576,528
Accumulated Depreciation and Amortization	2,048,482	2,014,154
TOTAL - NET	3,589,365	3,562,374
OTHER NONCURRENT ASSETS		
Regulatory Assets	219,245	210,174
Long-term Risk Management Assets	920	1,500
Deferred Charges and Other	63,328	36,696
TOTAL	283,493	248,370
TOTAL ASSETS	$ 4,228,568	$ 4,253,085

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 EQUITY
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 2,526
Accounts Payable:		
General	121,185	133,538
Affiliated Companies	56,181	51,040
Short-term Debt – Nonaffiliated	6,559	7,172
Long-term Debt Due Within One Year – Nonaffiliated	4,406	4,406
Long-term Debt Due Within One Year – Affiliated	50,000	-
Risk Management Liabilities	7,565	6,735
Customer Deposits	38,211	35,622
Accrued Taxes	92,538	33,744
Accrued Interest	16,487	36,647
Regulatory Liability for Over-Recovered Fuel Costs	6,380	5,162
Provision for Revenue Refund	26,957	54,100
Other	59,117	97,373
TOTAL	485,586	468,065
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,422,744	1,423,743
Long-term Debt – Affiliated	-	50,000
Long-term Risk Management Liabilities	528	516
Deferred Income Taxes	386,089	403,125
Regulatory Liabilities and Deferred Investment Tax Credits	333,386	335,749
Asset Retirement Obligations	52,018	53,433
Employment Benefits and Pension Obligations	123,689	117,772
Deferred Credits and Other	142,328	147,056
TOTAL	2,460,782	2,531,394
TOTAL LIABILITIES	2,946,368	2,999,459
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,697
Commitments and Contingencies (Note 4)		
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	549,979	530,003
Retained Earnings	623,140	615,110
Accumulated Other Comprehensive Income (Loss)	(31,574)	(32,120)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,277,205	1,248,653
Noncontrolling Interest	298	276
TOTAL EQUITY	1,277,503	1,248,929
TOTAL LIABILITIES AND EQUITY	$ 4,228,568	$ 4,253,085

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 Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 11,700	$ 5,605
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	36,792	36,136
Deferred Income Taxes	(27,042)	3,804
Allowance for Equity Funds Used During Construction	(6,405)	(3,063)
Mark-to-Market of Risk Management Contracts	(752)	(14,231)
Deferred Property Taxes	(29,792)	(29,799)
Change in Other Noncurrent Assets	6,230	6,589
Change in Other Noncurrent Liabilities	331	(14,680)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	94,646	22,169
Fuel, Materials and Supplies	(4,775)	(1,874)
Accounts Payable	(2,717)	7,398
Accrued Taxes, Net	58,794	21,279
Accrued Interest	(20,160)	749
Fuel Over/Under-Recovery, Net	26,786	(39,888)
Other Current Assets	326	7,683
Other Current Liabilities	(50,492)	(11,030)
Net Cash Flows from (Used for) Operating Activities	93,470	(3,153)
INVESTING ACTIVITIES		
Construction Expenditures	(169,603)	(125,358)
Change in Other Cash Deposits	(954)	(585)
Change in Advances to Affiliates, Net	(37,649)	-
Proceeds from Sales of Assets	104,824	66
Net Cash Flows Used for Investing Activities	(103,382)	(125,877)
FINANCING ACTIVITIES		
Capital Contribution from Parent	17,500	50,000
Issuance of Long-term Debt – Nonaffiliated	(15)	-
Change in Short-term Debt, Net – Nonaffiliated	(613)	(285)
Change in Advances from Affiliates, Net	(2,526)	87,645
Retirement of Long-term Debt – Nonaffiliated	(1,101)	(1,851)
Principal Payments for Capital Lease Obligations	(2,334)	(1,312)
Dividends Paid on Common Stock – Nonaffiliated	(1,115)	(949)
Dividends Paid on Cumulative Preferred Stock	(57)	(57)
Net Cash Flows from Financing Activities	9,739	133,191
Net Increase (Decrease) in Cash and Cash Equivalents	(173)	4,161
Cash and Cash Equivalents at Beginning of Period	1,910	1,742
Cash and Cash Equivalents at End of Period	$ 1,737	$ 5,903
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 51,573	$ 14,049
Net Cash Paid (Received) for Income Taxes	(1,117)	641
Noncash Acquisitions Under Capital Leases	1,568	6,796
Construction Expenditures Included in Accounts Payable at March 31,	72,331	63,973

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	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.	Benefit Plans	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
6.	Business Segments	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
7.	Derivatives, Hedging and Fair Value Measurements	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 months March 31, 2009 is not necessarily indicative of results that may be expected for the year ending December 31, 2009. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2008 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2008 as filed with the SEC on February 27, 2009.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether they are the primary beneficiary of a VIE, each Registrant Subsidiary considers factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine and DHLC. OPCo is the primary beneficiary of JMG. APCo, CSPCo, I&M, OPCo, PSO and SWEPCo each hold a significant variable interest in AEPSC. I&M and CSPCo each hold a significant variable interest in AEGCo.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee which is included in Fuel and Other Consumables Used for Electric Generation on SWEPCo's Condensed Consolidated Statements of Income. Based on these facts, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended March 31, 2009 and 2008 were $35 million and $20 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's Condensed Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC's debt. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate DHLC. SWEPCo's total billings from DHLC for the three months ended March 31, 2009 and 2008 were $11 million and $12 million, respectively. These billings are included in Fuel and Other Consumables Used for Electric Generation on SWEPCo's Condensed Consolidated Statements of Income. See the tables below for the classification of DHLC assets and liabilities on SWEPCo's Condensed Consolidated Balance Sheets.

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED VARIABLE INTEREST ENTITIES
March 31, 2009
(in millions)

	Sabine	DHLC
ASSETS		
Current Assets	$ 34	$ 18
Net Property, Plant and Equipment	122	32
Other Noncurrent Assets	30	11
Total Assets	$ 186	$ 61
LIABILITIES AND EQUITY		
Current Liabilities	$ 34	$ 12
Noncurrent Liabilities	152	45
Equity	-	4
Total Liabilities and Equity	$ 186	$ 61

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED VARIABLE INTEREST ENTITIES
December 31, 2008
(in millions)

	Sabine	DHLC
ASSETS		
Current Assets	$ 33	$ 22
Net Property, Plant and Equipment	117	33
Other Noncurrent Assets	24	11
Total Assets	$ 174	$ 66
LIABILITIES AND EQUITY		
Current Liabilities	$ 32	$ 18
Noncurrent Liabilities	142	44
Equity	-	4
Total Liabilities and Equity	$ 174	$ 66

OPCo has a lease agreement with JMG to finance OPCo's FGD system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments are the only form of repayment associated with JMG's debt obligations even though OPCo does not guarantee JMG's debt. The creditors of JMG have no recourse to any AEP entity other than OPCo for the lease payment. OPCo does not have any ownership interest in JMG. Based on the structure of the entity, management has concluded that OPCo is the primary beneficiary and is required to consolidate JMG. OPCo's total billings from JMG for the three months ended March 31, 2009 and 2008 were $17 million and $12 million, respectively. See the tables below for the classification of JMG's assets and liabilities on OPCo's Condensed Consolidated Balance Sheets.

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

OHIO POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITY
March 31, 2009
(in millions)

	JMG
ASSETS	
Current Assets	$ 13
Net Property, Plant and Equipment	417
Other Noncurrent Assets	1
Total Assets	$ 431
LIABILITIES AND EQUITY	
Current Liabilities	$ 156
Noncurrent Liabilities	257
Equity	18
Total Liabilities and Equity	$ 431

OHIO POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITY
December 31, 2008
(in millions)

	JMG
ASSETS	
Current Assets	$ 11
Net Property, Plant and Equipment	423
Other Noncurrent Assets	1
Total Assets	$ 435
LIABILITIES AND EQUITY	
Current Liabilities	$ 161
Noncurrent Liabilities	257
Equity	17
Total Liabilities and Equity	$ 435

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. No AEP subsidiary has provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations by cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP's subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. All Registrant Subsidiaries are considered to have a significant interest in the variability in AEPSC due to their activity in AEPSC's cost reimbursement structure. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Three Months Ended March 31,	
	2009	**2008**
Company	**(in millions)**	
APCo	$ 50	$ 62
CSPCo	29	32
I&M	29	40
OPCo	41	51
PSO	21	30
SWEPCo	29	34

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	March 31, 2009		**December 31, 2008**	
	As Reported in the Balance Sheet	**Maximum Exposure**	**As Reported in the Balance Sheet**	**Maximum Exposure**
	(in millions)			
APCo	$ 14	$ 14	$ 27	$ 27
CSPCo	9	9	15	15
I&M	8	8	14	14
OPCo	11	11	21	21
PSO	6	6	10	10
SWEPCo	8	8	14	14

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. In May 2007, AEGCo began leasing the Lawrenceburg Generating Station to CSPCo. AEP guarantees all the debt obligations of AEGCo. I&M and CSPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and CSPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. Due to the nature of the AEP Power Pool, there is a sharing of the cost of Rockport and Lawrenceburg Plants such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport or Lawrenceburg Plants. In the event AEGCo would require financing or other support outside the billings to I&M, CSPCo and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 13 in the 2008 Annual Report.

Total billings from AEGCo were as follows:

	Three Months Ended March 31, 2009	2008
	(in millions)	
CSPCo	$ 17	$ 24
I&M	63	59

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

	March 31, 2009		December 31, 2008	
	As Reported in the Consolidated Balance Sheet	Maximum Exposure	As Reported in the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
CSPCo	$ 6	$ 6	$ 5	$ 5
I&M	21	21	23	23

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrant Subsidiaries recognize the revenues on their statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

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

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income.

CSPCo and OPCo Revised Depreciation Rates

Effective January 1, 2009, CSPCo and OPCo revised book depreciation rates for generating plants consistent with a recently completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain OPCo generating facilities. The impact of the change in depreciation rates was an increase in OPCo's depreciation expense of $17 million and a decrease in CSPCo's depreciation expense of $4 million when comparing the three months ended March 31, 2009 and 2008.

Acquisition – Oxbow Mine Lignite – Affecting SWEPCo

In April 2009, SWEPCo and its wholly-owned lignite mining subsidiary, Dolet Hills Mining Company, LLC (DHLC), agreed to purchase 50% of the Oxbow Mine lignite reserves and 100% of all associated mining equipment and assets from The North American Coal Corporation and its affiliates, Red River Mining Company and Oxbow Property Company, LLC for $42 million. Cleco Power LLC (Cleco), will acquire the remaining 50% of the lignite reserves. Consummation of the transaction is subject to regulatory approval by the LPSC and the APSC and the transfer of other regulatory instruments. If approved, DHLC will acquire and own the Oxbow Mine mining equipment and related assets and it will operate the Oxbow Mine. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for SWEPCo's and Cleco's jointly-owned Dolet Hills Generating Station.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of final pronouncements issued or implemented in 2009 and standards issued but not implemented that management has determined relate to the Registrant Subsidiaries' operations.

Pronouncements Adopted During the First Quarter of 2009

The following standards were effective during the first quarter of 2009. Consequently, the financial statements and footnotes reflect their impact.

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 established 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. The standard 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 can affect tax positions on previous acquisitions. The Registrant Subsidiaries do not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

The Registrant Subsidiaries adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. The Registrant Subsidiaries will apply it to any future business combinations.

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

The Registrant Subsidiaries adopted SFAS 160 effective January 1, 2009 and retrospectively applied the standard to prior periods. The adoption of SFAS 160 had no impact on APCo, CSPCo, I&M and PSO. The retrospective application of this standard impacted OPCo and SWEPCo as follows:

OPCo:

- Reclassifies Interest Expense of $463 thousand for the three months ended March 31, 2008 as Net Income Attributable to Noncontrolling Interest below Net Income in the presentation of Earnings Attributable to OPCo Common Shareholder in its Condensed Consolidated Statements of Income.
- Reclassifies minority interest of $16.8 million as of December 31, 2008 previously included in Deferred Credits and Other and Total Liabilities as Noncontrolling Interest in Total Equity on its Condensed Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interest in its Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $463 thousand for the three months ended March 31, 2008 from Operating Activities to Financing Activities in the Condensed Consolidated Statements of Cash Flows.

SWEPCo:

- Reclassifies Minority Interest Expense of $995 thousand for the three months ended March 31, 2008 as Net Income Attributable to Noncontrolling Interest below Net Income in the presentation of Earnings Attributable to SWEPCo Common Shareholder in its Condensed Consolidated Statements of Income.
- Reclassifies minority interest of $276 thousand as of December 31, 2008 previously included in Deferred Credits and Other and Total Liabilities as Noncontrolling Interest in Total Equity on its Condensed Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interest in the Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $949 thousand for the three months ended March 31, 2008 from Operating Activities to Financing Activities in the Condensed Consolidated Statements of Cash Flows.

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 an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

The Registrant Subsidiaries adopted SFAS 161 effective January 1, 2009. This standard increased the disclosures related to derivative instruments and hedging activities. See "Derivatives and Hedging" section of Note 7 for further information.

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 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. 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.

The Registrant Subsidiaries adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

The Registrant Subsidiaries adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

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. 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.

The Registrant Subsidiaries adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2)

In February 2008, the FASB issued 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). 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. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

The Registrant Subsidiaries adopted SFAS 157-2 effective January 1, 2009. The Registrant Subsidiaries will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. The Registrant Subsidiaries did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first quarter of 2009.

<u>Pronouncements Effective in the Future</u>

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

This standard is effective for interim periods ending after June 15, 2009. Management expects this standard to increase the disclosure requirements related to financial instruments. The Registrant Subsidiaries will adopt the standard effective second quarter of 2009.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

This standard is effective for interim periods ending after June 15, 2009. Management does not expect a material impact as a result of the new OTTI evaluation method for debt securities, but expects this standard to increase the disclosure requirements related to financial instruments. The Registrant Subsidiaries will adopt the standard effective second quarter of 2009.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. The Registrant Subsidiaries will adopt the standard effective for the 2009 Annual Report.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

This standard is effective for interim and annual periods ending after June 15, 2009. Management expects this standard to have no impact on the financial statement but will increase disclosure requirements. The Registrant Subsidiaries will adopt the standard effective second quarter of 2009.

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, insurance, hedge accounting, discontinued operations, 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.

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 2008 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 2009 and updates the 2008 Annual Report.

Ohio Rate Matters

Ohio Electric Security Plan Filings – Affecting CSPCo and OPCo

In July 2008, as required by the 2008 amendments to the Ohio restructuring legislation, CSPCo and OPCo filed ESPs with the PUCO to establish standard service offer rates. CSPCo and OPCo did not file an optional Market Rate Offer (MRO). CSPCo's and OPCo's ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a fuel adjustment clause (FAC) that includes fuel costs, purchased power costs, consumables such as urea, gains and losses on sales of emission allowances and most other variable production costs. FAC costs were proposed to be phased into customer bills over the three-year period from 2009 through 2011 with unrecovered FAC costs to be recorded as a FAC phase-in regulatory asset. The phase-in regulatory asset deferral along with a deferred weighted average cost of capital carrying cost was proposed to be recovered over seven years from 2012 through 2018.

In March 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the FAC. The ordered increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. After final PUCO review and approval of conforming rate schedules, CSPCo and OPCo implemented rates for the April 2009 billing cycle. CSPCo and OPCo will collect the 2009 annualized revenue increase over the remainder of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. As of March 31, 2009, the FAC deferral balances were $17 million and $66 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales. In addition, the ESP order provided for both the FAC deferral credits and the off-system sales margins to be excluded from the methodology for the Significantly Excessive Earnings Test (SEET). The SEET is discussed below.

Additionally, the order addressed several other items, including:

- The approval of new distribution riders, subject to true-up for recovery of costs for enhanced vegetation management programs, for CSPCo and OPCo and the proposed gridSMART advanced metering initial program roll out in a portion of CSPCo's service territory. The PUCO proposed that CSPCo mitigate the costs of gridSMART by seeking matching funds under the American Recovery and Reinvestment Act of 2009. As a result, a rider was established to recover 50% or $32 million of the projected $64 million revenue requirement related to gridSMART costs. The PUCO denied the other distribution system reliability programs proposed by CSPCo and OPCo as part of their ESP filings. The PUCO decided that those requests should be examined in the context of a complete distribution base rate case. The order did not require CSPCo and/or OPCo to file a distribution base rate case.

- The approval of CSPCo's and OPCo's request to recover the incremental carrying costs related to environmental investments made from 2001 through 2008 that are not reflected in existing rates. Future recovery during the ESP period of incremental carrying charges on environmental expenditures incurred beginning in 2009 may be requested in annual filings.

- The approval of a $97 million and $55 million increase in CSPCo's and OPCo's Provider of Last Resort charges, respectively, to compensate for the risk of customers changing electric suppliers during the ESP period.

- The requirement that CSPCo's and OPCo's shareholders fund a combined minimum of $15 million in costs over the ESP period for low-income, at-risk customer programs. This funding obligation was recognized as a liability and an unfavorable adjustment to Other Operation and Maintenance expense for the three-month period ending March 31, 2009.

- The deferral of CSPCo's and OPCo's request to recover certain existing regulatory assets, including customer choice implementation and line extension carrying costs as part of the ESPs. The PUCO decided it would be more appropriate to consider this request in the context of CSPCo's and OPCo's next distribution base rate case. These regulatory assets, which were approved by prior PUCO orders, total $58 million for CSPCo and $40 million for OPCo as of March 31, 2009. In addition, CSPCo and OPCo would recover and recognize as income, when collected, $35 million and $26 million, respectively, of related unrecorded equity carrying costs incurred through March 2009.

Finally, consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the SEET that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings as measured by whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that have comparable business and financial risk. If the rate adjustments, in the aggregate, result in significantly excessive earnings in comparison, the PUCO must require that the amount of the excess be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until the second or third quarter of 2010.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP, not to the effective date of tariffs and clarified the tariffs were not retroactive. In March 2009, CSPCo and OPCo implemented the new ESP tariffs effective with the start of the April 2009 billing cycle. In April 2009, CSPCo and OPCo filed a motion requesting rehearing of several issues. In April 2009, several intervenors filed motions requesting rehearing of issues underlying the PUCO's authorized rate increases and one intervenor filed a motion requesting the PUCO to direct CSPCo and OPCo to cease collecting rates under the order. Certain intervenors also filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases.

Management will evaluate whether it will withdraw the ESP applications after a final order, thereby terminating the ESP proceedings. If CSPCo and/or OPCo withdraw the ESP applications, CSPCo and/or OPCo may file an MRO or another ESP as permitted by the law. The revenues collected and recorded in 2009 under this PUCO order are subject to possible refund through the SEET process. Management is unable, due to the decision of the PUCO to defer guidance on the SEET methodology to a future generic SEET proceeding, to estimate the amount, if any, of a possible refund that could result from the SEET process in 2010.

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. In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover 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 pre-construction cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest.

In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest. In October 2008, 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.

In January 2009, a PUCO Attorney Examiner issued an order that CSPCo and OPCo file a detailed statement outlining the status of the construction of the IGCC plant, including whether CSPCo and OPCo are engaged in a continuous course of construction on the IGCC plant. In February 2009, CSPCo and OPCo filed a statement that CSPCo and OPCo have not commenced construction of the IGCC plant and believe there exist real statutory barriers to the construction of any new base load generation in Ohio, including IGCC plants. The statement also indicated that while construction on the IGCC plant might not begin by June 2011, changes in circumstances could result in the commencement of construction on a continuous course by that time.

Management continues to pursue the ultimate construction of the IGCC plant. However, CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists. 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. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what, if any effect, the litigation will have on future net income and cash flows.

Ormet – Affecting CSPCo and OPCo

In December 2008, CSPCo, OPCo and Ormet, a large aluminum company with a load of 520 MW, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. The arrangement would be effective January 1, 2009 and remain in effect and expire upon the effective date of CSPCo's and OPCo's new ESP rates and the effective date of a new arrangement between Ormet and CSPCo/OPCo as approved by the PUCO. Under the interim arrangement, Ormet would pay the then-current applicable generation tariff rates and riders. CSPCo and OPCo sought to defer as a regulatory asset beginning in 2009 the difference between the PUCO approved 2008 market price of $53.03 per MWH and the applicable generation tariff rates and riders. CSPCo and OPCo proposed to recover the deferral through the fuel adjustment clause mechanism they proposed in the ESP proceeding. In January 2009, the PUCO approved the application as an interim arrangement. In February 2009, an intervenor filed an application for rehearing of the PUCO's interim arrangement approval. In March 2009, the PUCO granted that application for further consideration of the matters specified in the rehearing application.

In February 2009, as amended in April 2009, Ormet filed an application with the PUCO for approval of a proposed Ormet power contract for 2009 through 2018. Ormet proposed to pay varying amounts based on certain conditions, including the price of aluminum and the level of production. The difference between the amounts paid by Ormet and the otherwise applicable PUCO ESP tariff rate would be either collected from or refunded to CSPCo's and OPCo's retail customers.

In March 2009, the PUCO issued an order in the ESP filings which included approval of a FAC for the ESP period. The approval of an ESP FAC, together with the January 2009 PUCO approval of the Ormet interim arrangement, provided the basis to record regulatory assets of $10 million and $9 million for CSPCo and OPCo, respectively, for the differential in the approved market price of $53.03 versus the rate paid by Ormet during the first quarter of 2009. These amounts are included in CSPCo's and OPCo's FAC phase-in deferral balance of $17 million and $66 million, respectively. See "Ohio Electric Security Plan Filings" section above.

The pricing and deferral authority under the PUCO's January 2009 approval of the interim arrangement will continue until the 2009-2018 power contract becomes effective. Management cannot predict when or if the PUCO will approve the new power contract.

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. Under the RSP, which was effective in 2008, CSPCo and OPCo could 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 expected recovery of the storm restoration costs. In December 2008, CSPCo and OPCo filed with the PUCO a request to establish the regulatory assets under the terms of the RSP, plus accrue carrying costs on the unrecovered balance using CSPCo's and OPCo's weighted average cost of capital carrying charge rates. In December 2008, the PUCO subsequently approved the establishment of the regulatory assets but authorized CSPCo and OPCo to record a long-term debt only carrying cost on the regulatory asset. In its order approving the deferrals, the PUCO stated that the mechanism for recovery would be determined in CSPCo's and OPCo's next distribution rate filing.

In December 2008, the Consumers for Reliable Electricity in Ohio filed a request with the PUCO asking for an investigation into the service reliability of Ohio's investor-owned electric utilities, including CSPCo and OPCo. The investigation request included the widespread outages caused by the September 2008 wind storm. CSPCo and OPCo filed a response asking the PUCO to deny the request.

As a result of the past favorable treatment of storm restoration costs under the RSP and the RSP recovery provisions, which were in effect when the storm occurred and the filings made, management believes the recovery of the regulatory assets is probable. However, if these regulatory assets are not recovered, it would have an adverse effect on future net income and cash flows.

Texas Rate Matters

Texas Restructuring – SPP – Affecting SWEPCo

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In April 2009, the Texas Senate passed a bill related to SWEPCo's SPP area of Texas that requires cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all retail customer classes. The bill is expected to be reviewed by the Texas House of Representatives which, if passed, would be sent to the governor of Texas for approval. If the bill is signed, management may be required to re-apply SFAS 71 for the generation portion of SWEPCo's Texas jurisdiction. The initial reapplication of SFAS 71 regulatory accounting would likely result in an extraordinary loss.

Stall Unit

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

Turk Plant

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

Virginia Rate Matters

Virginia E&R Costs Recovery Filing – Affecting APCo

Due to the recovery provisions in Virginia law, APCo has been deferring incremental E&R costs as incurred, excluding the equity return on non-CWIP capital investments, pending future recovery. In October 2008, the Virginia SCC approved a stipulation agreement to recover $61 million of incremental E&R costs incurred from October 2006 to December 2007 through a surcharge in 2009 which will have a favorable effect on cash flows of $61 million and on net income for the previously unrecognized equity portion of the carrying costs of approximately $11 million.

The Virginia E&R cost recovery mechanism under Virginia law ceased effective with costs incurred through December 2008. However, the 2007 amendments to Virginia's electric utility restructuring law provide for a rate adjustment clause to be requested in 2009 to recover incremental E&R costs incurred through December 2008. Under this amendment, APCo will request recovery of its 2008 unrecovered incremental E&R costs in a planned May 2009 filing. As of March 31, 2009, APCo has $109 million of deferred Virginia incremental E&R costs (excluding $22 million of unrecognized equity carrying costs). The $109 million consists of $6 million of over recovery of costs collected from the 2008 surcharge, $36 million approved by the Virginia SCC related to the 2009 surcharge and $79 million, representing costs deferred during 2008, to be included in the 2009 E&R filing, for collection in 2010.

If the Virginia SCC were to disallow a material portion of APCo's 2008 deferred incremental E&R costs, it would have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant – Affecting APCo

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

In June 2007, APCo sought pre-approval from the WVPSC for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing finance costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. In March 2008, the WVPSC granted APCo the CPCN to build the plant and approved the requested cost recovery. In March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed IGCC plant. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009. The $45 million included 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 carrying cost on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered.

The Virginia SCC issued an order in April 2008 denying APCo's requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. 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 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. Various parties, including APCo, filed comments but the WVPSC has not taken any action.

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

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.

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 demonstration 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. RWE AG, a German electric power and natural gas public utility, is participating in the project and is providing some funding to offset APCo's costs. APCo's estimated cost for its share of the facilities is $73 million. Through March 31, 2009, APCo incurred $45 million in capitalized project costs which are included in Regulatory Assets. APCo earns a return on the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the Virginia SCC in November 2008. APCo plans to seek recovery for the CO_2 capture and storage project costs including a return on the additional investment since June 2008 in its next Virginia and West Virginia base rate filings which are expected to be filed in 2009. If a significant portion of the deferred project costs are excluded from base rates and ultimately disallowed in future Virginia or West Virginia rate proceedings, it could have an adverse effect on future net income and cash flows.

West Virginia Rate Matters

APCo's 2009 Expanded Net Energy Cost (ENEC) Filing – Affecting APCo

In March 2009, APCo filed an annual ENEC filing with the WVPSC for an increase of approximately $398 million for incremental fuel, purchased power and environmental compliance project expenses, to become effective July 2009. Within the filing, APCo requested the WVPSC to allow APCo to temporarily adopt a modified ENEC mechanism due to the distressed economy. The proposed modified ENEC mechanism provides that all deferred ENEC amounts as of June 30, 2009 be recovered over a five-year period beginning in July 2009. The mechanism also extends cost projections out for a period of three years through June 30, 2012 and provides for three annual increases to recover projected future ENEC cost increases. APCo is also requesting all deferred amounts that exceed the deferred amounts that would have existed under the traditional ENEC mechanism be subject to a carrying charge based upon APCo's weighted average cost of capital. As filed, the modified ENEC mechanism would produce three annual increases, including carrying charges, of $170 million, $149 million and $155 million, effective July 2009, 2010 and 2011, respectively.

In March 2009, the WVPSC issued an order suspending the rate increase request until December 2009. In April 2009, APCo filed a motion for approval of an interim rate increase of $162 million, effective July 2009 and subject to refund pending the final adjudication of the ENEC by December 2009. In April 2009, the WVPSC granted intervention to several parties and heard oral arguments from APCo and intervenors on the requested interim ENEC filing. If the WVPSC were to disallow a material portion of APCo's requested increase, it would have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant – Affecting APCo

See "APCo's Filings for an IGCC Plant" section within "Virginia Rate Matters" for disclosure.

Mountaineer Carbon Capture Project – Affecting APCo

See "Mountaineer Carbon Capture Project" section within "Virginia Rate Matters" for disclosure.

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 included a $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. In addition, I&M proposed to share with customers, through a proposed tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In December 2008, I&M and all of the intervenors jointly filed a settlement agreement with the IURC proposing to resolve all of the issues in the case. The settlement agreement incorporated the $69 million annual reduction in revenues from depreciation rate reduction in the development of the agreed to revenue increase of $44 million including a $22 million increase in revenue from base rates with an authorized return on equity of 10.5% and a $22 million initial increase in tracker revenue for PJM, net emission allowance and DSM costs. The agreement also establishes an off-system sales sharing mechanism and other provisions which include continued funding for the eventual decommissioning of the Cook Nuclear Plant. In March 2009, the IURC approved the settlement agreement, with modifications, that provides for an annual increase in revenues of $42 million including a $19 million increase in revenue from base rates, net of the depreciation rate reduction, and a $23 million increase in tracker revenue. The IURC order removed base rate recovery of the DSM costs but established a tracker with an initial zero amount for DSM costs, adjusted the sharing of off-system sales margins to 50% above the $37.5 million included in base rates and approved the recovery of $7.3 million of previously expensed NSR and OPEB costs which favorably affected first quarter of 2009 net income. In addition, the IURC order requires I&M to review and file a final report by December 2009 on the effectiveness of the Interconnection Agreement including I&M's relationship with PJM.

Rockport and Tanners Creek Plants – Affecting I&M

In January 2009, I&M filed a petition with the IURC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to use advanced coal technology which would allow I&M to reduce airborne emissions of NO_x and mercury from its existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition is requesting approval to construct and recover the costs of selective non-catalytic reduction (SNCR) systems at the Tanners Creek Plant and to recover the costs of activated carbon injection (ACI) systems on both generating units at the Rockport Plant. I&M is requesting to depreciate the ACI systems over an accelerated 10-year period and the SNCR systems over the remaining useful life of the Tanners Creek generating units. I&M requested the IURC to approve a rate adjustment mechanism of unrecovered carrying costs during construction and a return on investment, depreciation expense and operation and maintenance costs, including consumables and new emission allowance costs, once the projects are placed in service. I&M also requested the IURC to authorize the deferral of the cost of service of these projects and carrying costs until such costs are recognized in the requested rate adjustment mechanism. Through March 2009, I&M incurred $9 million and $6 million in capitalized project costs related to the Rockport and Tanners Creek Plants, respectively, which are included in Construction Work in Progress. In March 2009, the IURC issued a prehearing conference order setting a procedural schedule. Since the Indiana base rate order included recovery of emission allowance costs, that portion of this request will be eliminated. An order is expected by the third quarter of 2009. Management is unable to predict the outcome of this petition.

Indiana Fuel Clause Filing – Affecting I&M

In January 2009, I&M filed with the IURC an application to increase its fuel adjustment charge by approximately $53 million for April through September 2009. The filing included an under-recovery for the period ended November 2008, mainly as a result of the extended outage of the Cook Plant Unit 1 (Unit 1) due to fire damage to the main turbine and generator, increased coal prices and a projection for the future period of fuel costs including Unit 1 fire related outage replacement power costs. The filing also included an adjustment, beginning coincident with the receipt of insurance proceeds, to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Unit 1 accidental outage policy. See “Cook Plant Unit 1 Fire and Shutdown” section of Note 4. I&M reached an agreement in February 2009 with intervenors, which was approved by the IURC in March 2009, to collect the under-recovery over twelve months instead of over six months as proposed. Under the order, the fuel factor will go into effect, subject to refund, and a subdocket will be established to consider issues relating to the Unit 1 fire outage, the use of the insurance proceeds and I&M’s fuel procurement practices. The order provides for the fire outage issues to be resolved subsequent to the date Unit 1 returns to service, which if temporary repairs are successful, could occur as early as October 2009. Management cannot predict the outcome of the pending proceedings, including the treatment of the insurance proceeds, and whether any fuel clause revenues will have to be refunded as a result.

Michigan Rate Matters – *Affecting I&M*

In March 2009, I&M filed with the Michigan Public Service Commission its 2008 power supply cost recovery reconciliation. The filing also included an adjustment to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Cook Plant Unit 1 accidental outage policy. See “Cook Plant Unit 1 Fire and Shutdown” section of Note 4. Management is unable to predict the outcome of this proceeding and its possible effect on future net income and cash flows.

Oklahoma Rate Matters

PSO Fuel and Purchased Power – Affecting PSO

2006 and Prior Fuel and Purchased Power

Proceedings addressing PSO’s historic fuel costs from 2001 through 2006 remain open at the OCC due to the issue of the allocation of off-system sales margins among the AEP operating companies in accordance with a FERC-approved allocation agreement.

In 2002, PSO under-recovered $42 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to 2002. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed an ALJ recommendation that concluded it was a FERC jurisdictional matter which allowed PSO to retain the $42 million it recovered from ratepayers. The OIEC requested that PSO be required to refund the $42 million through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending. For further discussion and estimated effect on net income, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

<u>*2007 Fuel and Purchased Power*</u>

In September 2008, the OCC initiated a review of PSO's generation, purchased power and fuel procurement processes and costs for 2007. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

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 (later adjusted to $127 million) on an annual basis. PSO has been recovering costs related to new peaking units recently placed into service through a Generation Cost Recovery Rider (GCRR). Subsequent to implementation of the new base rates, the GCRR will terminate and PSO will recover these costs through the new base rates. Therefore, PSO's net annual requested increase in total revenues was actually $117 million (later adjusted to $111 million). The proposed revenue requirement reflected a return on equity of 11.25%.

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues and a 10.5% return on equity. The rate increase includes a $59 million increase in base rates and a $22 million increase for costs to be recovered through riders outside of base rates. The $22 million increase includes $14 million for purchase power capacity costs and $8 million for the recovery of carrying costs associated with PSO's program to convert overhead distribution lines to underground service. The $8 million recovery of carrying costs associated with the overhead to underground conversion program will occur only if PSO makes the required capital expenditures. The final order approved lower depreciation rates and also provides for the deferral of $6 million of generation maintenance expenses to be recovered over a six-year period. This deferral was recorded in the first quarter of 2009. Additional deferrals were approved for distribution storm costs above or below the amount included in base rates and for certain transmission reliability expenses. The new rates reflecting the final order were implemented with the first billing cycle of February 2009.

PSO filed an appeal with the Oklahoma Supreme Court challenging an adjustment the OCC made on prepaid pension funding contained within the OCC final order. In February 2009, the Oklahoma Attorney General and several intervenors also filed appeals with the Oklahoma Supreme Court raising several issues. If the Attorney General and/or the intervenor's Supreme Court appeals are successful, it could have an adverse effect on future net income and cash flows.

<u>**Louisiana Rate Matters**</u>

2008 Formula Rate Filing – Affecting SWEPCo

In April 2008, SWEPCo filed the first formula rate plan (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 August 2008, SWEPCo implemented the FRP rates, subject to refund. No provision for refund has been recorded as SWEPCo believes that the rates as implemented are in compliance with the FRP methodology approved by the LPSC. The LPSC has not approved the rates being collected. If the rates are not approved as filed, it could have an adverse effect on future net income and cash flows.

2009 Formula Rate Filing – Affecting SWEPCo

In April 2009, SWEPCo filed the second FRP which would increase its annual Louisiana retail rates by an additional $4 million in August 2009 pursuant to the formula rate methodology. SWEPCo believes that the rates as filed are in compliance with the FRP methodology previously approved by the LPSC.

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 $385 million, excluding AFUDC, and is expected to be in-service in mid-2010. The Louisiana Department of Environmental Quality issued an air permit for the Stall unit in March 2008.

In March 2007, the PUCT approved SWEPCo's request for a certificate of necessity for the facility based on a prior cost estimate. In July 2008, a Louisiana ALJ issued a recommendation that SWEPCo be authorized to construct, own and operate the Stall Unit and recommended that costs be capped at $445 million (excluding transmission). In October 2008, the LPSC issued a final order effectively approving the ALJ recommendation. In December 2008, SWEPCo submitted an amended filing seeking approval from the APSC to construct the unit. The APSC staff filed testimony in March 2009 supporting the approval of the plant. The APSC staff also recommended that costs be capped at $445 million (excluding transmission). A hearing that had been scheduled for April 2009 was cancelled and the APSC will issue its decision based on the amended application and prefiled testimony.

If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized construction costs including any cancellation fees. As of March 31, 2009, SWEPCo has capitalized construction costs of $291 million (including AFUDC) and has contractual construction commitments of an additional $74 million. As of March 31, 2009, if the plant had been cancelled, cancellation fees of $40 million would have been required in order to terminate the 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. 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. During 2007, OMPA exercised its participation option. During the first quarter of 2009, AECC and ETEC exercised their participation options and paid SWEPCo $104 million. SWEPCo recorded a $2.2 million gain from the transactions. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's portion estimated to cost $1.2 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 Turk Plant. Certain landowners have appealed the APSC's decision 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 previously estimated $1.522 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. 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 emission costs exceed the restrictions, it could have a material adverse effect 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.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. 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 2009, SWEPCo filed a motion to dismiss the appeal. In March 2009, the motion was granted.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant's permit is heard. Hearings on the air permit appeal is scheduled for June 2009. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers a potential wetlands impact on approximately 2.5 acres at the Turk Plant. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas of the Turk Plant. The impact on the construction schedule and workforce is currently being evaluated by management.

In January and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications 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. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor's Commission on Global Warming issued its final report to the governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build and operate 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 costs incurred plus related shutdown costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of March 31, 2009, SWEPCo has capitalized approximately $480 million of expenditures (including AFUDC) and has contractual construction commitments for an additional $655 million. As of March 31, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $100 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.

Arkansas Base Rate Filing – Affecting SWEPCo

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to recover financing costs related to the construction of the Stall and Turk generating facilities. These financing costs are currently being capitalized as AFUDC in Arkansas. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

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 the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 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 are 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 of any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 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	$ 12.4
CSPCo	0.9	6.9
I&M	1.0	7.3
OPCo	1.3	9.4

In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. As of March 31, 2009, there were no in-process settlements. APCo's, CSPCo's, I&M's and OPCo's reserve balance at March 31, 2009 was:

Company	March 31, 2009 (in millions)
APCo	$ 10.7
CSPCo	5.9
I&M	6.3
OPCo	8.2

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 available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

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 state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. 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. In January and March 2009, AEP received retail rate increases in Tennessee and Indiana, respectively, that recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, AEP is now recovering approximately 98% of the lost T&O transmission revenues. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

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. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is 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 to reflect the resultant additional transmission cost reductions. 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 the AEP East companies' cost of service. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, established a settlement proceeding with an ALJ, and delayed the requested October 2008 effective date for five months. The requested increase, which the AEP East companies began billing in April 2009 for service as of March 1, 2009, will produce a $63 million annualized increase in revenues. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio are not directly affected. Retail rates for CSPCo and OPCo would be increased through the TCRR totaling approximately $10 million and $13 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. In October 2008, AEP filed the required compliance filing, and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing. Under the formula, rates will be updated effective July 1, 2009, and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Allocation of Off-system Sales Margins – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies shared a portion of such revenues with their wholesale and retail customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund. In January 2009, SWEPCo refunded approximately $13 million to FERC wholesale customers. In February 2009, SWEPCo filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction amount to be included in the March 2009 fuel cost report submitted to the PUCT. PSO began refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle. SWEPCo is working with the APSC and the LPSC to determine the effect the FERC order will have on retail rates. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding future regulatory proceedings is adequate.

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. A settlement agreement was reached and has been filed with the FERC. FERC approval is pending.

Transmission Equalization Agreement – Affecting APCo, CSPCo, I&M and OPCo

Certain transmission equipment placed in service in 1998 was inadvertently excluded from the AEP East companies' TEA calculation prior to January 2009. Management does not believe that it is probable that a material retroactive rate adjustment will result from the omission. However, if a retroactive adjustment is required for APCo, CSPCo, I&M and OPCo, it could have an adverse effect on future net income, cash flows and financial condition.

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 2008 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 – Affecting APCo, I&M, OPCo and SWEPCo

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 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.

The Registrant Subsidiaries and certain other companies in the AEP System have 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 March 31, 2009, $372 million of letters of credit were issued by Registrant Subsidiaries under the $650 million 3-year credit agreement to support variable rate Pollution Control Bonds. In April 2009, the $350 million 364-day credit agreement expired.

At March 31, 2009, the maximum future payments of the LOCs were as follows:

Company	Amount (in thousands)	Maturity	Borrower Sublimit
$1.5 billion LOC:			
I&M	$ 300	March 2010	N/A
SWEPCo	4,448	December 2009	N/A
$650 million LOC:			
APCo	$ 126,716	June 2010	$ 300,000
I&M	77,886	May 2010	230,000
OPCo	166,899	June 2010	400,000

Guarantees of Third-Party Obligations – Affecting 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 March 31, 2009, SWEPCo collected approximately $39 million through a rider for final mine closure costs, of which approximately $3 million is recorded in Other Current Liabilities, approximately $16 million is recorded in Asset Retirement Obligations and approximately $20 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 – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

Contracts

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 March 31, 2009, 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 Lease Agreements

Certain Registrant Subsidiaries lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2010 and 2011, the Registrant Subsidiaries will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into additional replacement leasing arrangements for the equipment affected by this notification prior to the termination dates of 2010 and 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At March 31, 2009, 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 thousands)
APCo	$ 1,055
CSPCo	431
I&M	720
OPCo	857
PSO	1,183
SWEPCo	799

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $20 million for I&M and $23 million for SWEPCo for the remaining railcars as of March 31, 2009.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five-year lease term to 77% at the end of the 20-year term of the projected fair market value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, 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 CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. modified certain units at their jointly-owned coal-fired generating units in violation of the NSR requirements of the CAA.

A case remains pending that could affect CSPCo's share of jointly-owned Beckjord Station. The Beckjord case had a liability trial in 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. Beckjord is operated by Duke Energy Ohio, Inc.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, CSPCo might have for civil penalties under the pending CAA proceedings for Beckjord. Management is also unable to predict the timing of resolution of these matters. If CSPCo does not prevail, management believes CSPCo can recover any capital and operating costs of additional pollution control equipment that may be required through future regulated rates or market prices of electricity. If CSPCo is unable to recover such costs or if material penalties are imposed, it would adversely affect net income, cash flows and possibly financial condition.

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 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 Texas Commission on Environmental Quality 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 actions 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 concluded in 2006. 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 which were provided in 2007. 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.

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. Costs are currently being incurred 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 and started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $4 million of expense during 2008. Based upon updated information, I&M recorded additional expense of $3 million in March 2009. As the remediation work is completed, I&M's cost may continue to increase. I&M cannot predict the amount of additional cost, if any.

Defective Environmental Equipment – Affecting CSPCo and OPCo

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on units utilizing the JBR technology. The retrofits on two units are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. Management intends to pursue contractual and other legal remedies if these issues with Black & Veatch are not resolved. If the AEP System is unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows or financial condition.

Cook Plant Unit 1 Fire and Shutdown – Affecting I&M

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

The refueling outage scheduled for the fall of 2009 for Unit 1 was rescheduled to the spring of 2010. Management anticipates that the loss of capacity from Unit 1 will not affect I&M's ability to serve customers due to the existence of sufficient generating capacity in the AEP Power Pool.

I&M maintains property insurance through NEIL with a $1 million deductible. As of March 31, 2009, I&M recorded $34 million in Prepayments and Other on the Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursement from NEIL for the cost incurred to date to repair the property damage. 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 for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In the first quarter of 2009, I&M recorded $54 million in revenues, including $9 million that were deferred at December 31, 2008, related to the accidental outage policy. In order to hold customers harmless, in the first quarter of 2009, I&M applied $20 million of the accidental outage insurance proceeds to reduce fuel underrecoveries reflecting recoverable fuel costs as if Unit 1 were operating. 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 assumed the duties of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. In December 2008, the court denied AEP's motion to dismiss the case. Management intends to vigorously defend against these allegations. Management believes a provision recorded in 2008 should be sufficient.

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. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. 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. Management is unable to predict the outcome of these proceedings or their ultimate impact on future net income and cash flows.

5. 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 table provides the components of AEP's net periodic benefit cost for the plans for the three months ended March 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 10	$ 10
Interest Cost	63	63	27	28
Expected Return on Plan Assets	(80)	(84)	(20)	(28)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	15	9	11	3
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 20

The following table provides the Registrant Subsidiaries' net periodic benefit cost (credit) for the plans for the three months ended March 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2009	2008	2009	2008
Company	(in thousands)			
APCo	$ 2,615	$ 835	$ 6,058	$ 3,699
CSPCo	688	(349)	2,638	1,498
I&M	3,485	1,821	4,358	2,423
OPCo	2,067	319	5,139	2,816
PSO	770	508	2,283	1,387
SWEPCo	1,208	935	2,363	1,376

AEP sponsors several trust funds with significant investments intended 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 from the December 31, 2008 balances due to decreases in the equity and fixed income markets. Although the asset values are currently lower than at year end, this decline has not affected the funds' ability to make their required payments.

6. 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.

7. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

Objectives for Utilization of Derivative Instruments

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

Strategies for Utilization of Derivative Instruments to Achieve Objectives

The Registrant Subsidiaries' strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal SFAS 133 hedging strategies. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under SFAS 133. Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of SFAS 133.

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

The following table represents the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of March 31, 2009:

Notional Volume of Derivative Instruments
March 31, 2009
(in thousands)

Primary Risk Exposure	Unit of Measure	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
Commodity:							
Power	MWHs	102,761	54,500	52,744	67,512	609	718
Coal	Tons	10,972	5,551	5,860	18,810	3,012	4,853
Natural Gas	MMBtus	37,953	20,129	19,480	24,935	4,887	5,760
Heating Oil and Gasoline	Gallons	871	360	415	627	494	466
Interest Rate	USD	$ 41,480	$ 21,959	$ 21,325	$ 28,946	$ 2,552	$ 3,207
Interest Rate and Foreign Currency	USD	$ -	$ -	$ -	$ 400,000	$ -	$ 3,918

Fair Value Hedging Strategies

At certain times, AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative transactions in order to manage an existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify an exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. This strategy is not actively employed by any of the Registrant Subsidiaries in 2009. During 2008, APCo had designated interest rate derivatives as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designate as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. The Registrant Subsidiaries do not hedge all commodity price risk. During 2009 and 2008, APCo, CSPCo, I&M and OPCo designated cash flow hedging relationships using these commodities.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial gasoline and heating oil derivative contracts in order mitigate price risk of future fuel purchases. The Registrant Subsidiaries do not hedge all fuel price risk. During 2009, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active for any of the Registrant Subsidiaries during 2008. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. The Registrant Subsidiaries do not hedge all interest rate exposure. During 2009 and 2008, APCo and OPCo designated interest rate derivatives as cash flow hedges.

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrant Subsidiaries do not hedge all foreign currency exposure. During 2009 and 2008, APCo, OPCo and SWEPCo designated foreign currency derivatives as cash flow hedges.

Accounting for Derivative Instruments and the Impact on the Financial Statements

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrant Subsidiaries also apply valuation adjustments for discounting, liquidity and credit quality.

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

According to FSP FIN 39-1, the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. 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 March 31, 2009 and December 31, 2008 balance sheets, the Registrant Subsidiaries netted cash 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:

	March 31, 2009		December 31, 2008	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
		(in thousands)		
APCo	$ 25,038	$ 36,012	$ 2,189	$ 5,621
CSPCo	13,279	19,092	1,229	3,156
I&M	12,851	18,481	1,189	3,054
OPCo	16,450	23,662	1,522	3,909
PSO	-	393	-	105
SWEPCo	-	456	-	124

The following table represents the gross fair value impact of the Registrant Subsidiaries' derivative activity on the Condensed Balance Sheets as of March 31, 2009:

Fair Value of Derivative Instruments
March 31, 2009

APCo	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 672,985	$ 8,048	$ -	$ (605,838)	$ 75,195
Long-Term Risk Management Assets	276,740	615	-	(212,584)	64,771
Total Assets	949,725	8,663	-	(818,422)	139,966
Current Risk Management Liabilities	645,041	1,996	-	(607,945)	39,092
Long-Term Risk Management Liabilities	258,749	419	-	(229,113)	30,055
Total Liabilities	903,790	2,415	-	(837,058)	69,147
Total MTM Derivative Contract Net Assets (Liabilities)	$ 45,935	$ 6,248	$ -	$ 18,636	$ 70,819

CSPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 354,953	$ 4,268	$ -	$ (319,634)	$ 39,587
Long-Term Risk Management Assets	146,110	326	-	(112,128)	34,308
Total Assets	501,063	4,594	-	(431,762)	73,895
Current Risk Management Liabilities	340,254	1,050	-	(320,743)	20,561
Long-Term Risk Management Liabilities	136,595	222	-	(120,894)	15,923
Total Liabilities	476,849	1,272	-	(441,637)	36,484
Total MTM Derivative Contract Net Assets (Liabilities)	$ 24,214	$ 3,322	$ -	$ 9,875	$ 37,411

I&M

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 347,018	$ 4,131	$ -	$ (312,391)	$ 38,758
Long-Term Risk Management Assets	142,607	315	-	(109,640)	33,282
Total Assets	489,625	4,446	-	(422,031)	72,040
Current Risk Management Liabilities	332,550	1,021	-	(313,470)	20,101
Long-Term Risk Management Liabilities	133,350	214	-	(118,124)	15,440
Total Liabilities	465,900	1,235	-	(431,594)	35,541
Total MTM Derivative Contract Net Assets (Liabilities)	$ 23,725	$ 3,211	$ -	$ 9,563	$ 36,499

OPCo

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 525,935	$ 5,288	$ 1,329	$ (469,192)	$ 63,360
Long-Term Risk Management Assets	210,595	404	-	(165,334)	45,665
Total Assets	736,530	5,692	1,329	(634,526)	109,025
Current Risk Management Liabilities	504,236	1,314	925	(470,580)	35,895
Long-Term Risk Management Liabilities	200,912	275	-	(176,192)	24,995
Total Liabilities	705,148	1,589	925	(646,772)	60,890
Total MTM Derivative Contract Net Assets (Liabilities)	$ 31,382	$ 4,103	$ 404	$ 12,246	$ 48,135

PSO

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 41,231	$ -	$ -	$ (33,599)	$ 7,632
Long-Term Risk Management Assets	7,811	-	-	(7,211)	600
Total Assets	49,042	-	-	(40,810)	8,232
Current Risk Management Liabilities	39,566	33	-	(33,892)	5,707
Long-Term Risk Management Liabilities	7,523	-	-	(7,143)	380
Total Liabilities	47,089	33	-	(41,035)	6,087
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,953	$ (33)	$ -	$ 225	$ 2,145

SWEPCo

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 57,959	$ -	$ -	$ (47,772)	$ 10,187
Long-Term Risk Management Assets	12,427	-	1	(11,508)	920
Total Assets	70,386	-	1	(59,280)	11,107
Current Risk Management Liabilities	55,344	30	301	(48,110)	7,565
Long-Term Risk Management Liabilities	11,956	-	-	(11,428)	528
Total Liabilities	67,300	30	301	(59,538)	8,093
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,086	$ (30)	$ (300)	$ 258	$ 3,014

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Condensed Balance Sheets on a net basis in accordance with FIN 39 "Offsetting of Amounts Related to Certain Contracts."

(b) Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with FSP FIN 39-1 and dedesignated risk management contracts.

The table below presents the Registrant Subsidiaries MTM activity of derivative risk management contracts for the three months ended March 31, 2009:

Amount of Gain (Loss) Recognized
on Risk Management Contracts
For the Three Months Ended March 31, 2009

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 9,817	$ 10,745	$ 18,178	$ 12,711	$ 1,255	$ 1,523
Sales to AEP Affiliates	(7,020)	(4,076)	(3,971)	(3,214)	(1,462)	(1,781)
Regulatory Assets	(755)	-	-	-	-	(41)
Regulatory Liabilities	38,861	11,628	6,940	13,856	334	386
Total Gain (Loss) on Risk Management Contracts	$ 40,903	$ 18,297	$ 21,147	$ 23,353	$ 127	$ 87

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Condensed Statements of Income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Condensed Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Condensed Statements of Income depending on the relevant facts and circumstances. However, unrealized and realized gains and losses in regulated jurisdictions (APCo, I&M, PSO and the non-Texas portion of SWEPCo) for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with SFAS 71.

Accounting for Fair Value Hedging Strategies

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

The Registrant Subsidiaries record realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on the Condensed Statements of Income. During the three months ended March 31, 2009, the Registrant Subsidiaries did not employ any fair value hedging strategies. During the three months ended 2008, APCo designated interest rate derivatives as fair value hedges and did not recognize any hedge ineffectiveness related to these derivative transactions.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivatives transactions for the purchase and sale of electricity, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale in the Condensed Statements of Income, depending on the specific nature of the risk being hedged. The Registrant Subsidiaries do not hedge all variable price risk exposure related to commodities. During the three months ended March 31, 2009 and 2008, APCo, CSPCo, I&M and OPCo recognized immaterial amounts in Net Income related to hedge ineffectiveness.

Beginning in 2009, the Registrant Subsidiaries executed financial heating oil and gasoline derivative contracts to hedge the price risk of diesel fuel and gasoline purchases. The Registrant Subsidiaries reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation and Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Condensed Statements of Income. The Registrant Subsidiaries do not hedge all fuel price exposure. During the three months ended March 31, 2009, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo recognized no hedge ineffectiveness related to this hedge strategy.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2009 and 2008, APCo and OPCo recognized immaterial amounts in Net Income related to hedge ineffectiveness.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Depreciation and Amortization expense in the Condensed Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. The Registrant Subsidiaries do not hedge all foreign currency exposure. During the three months ended March 31, 2009 and 2008, APCo, OPCo and SWEPCo recognized no hedge ineffectiveness related to this hedge strategy.

The following table provides details on designated, effective cash flow hedges included in AOCI on the Condensed Balance Sheets and the reasons for changes in cash flow hedges from January 1, 2009 to March 31, 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2009

Commodity Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Beginning Balance in AOCI as of January 1, 2009	$ 2,726	$ 1,531	$ 1,482	$ 1,898	$ -	$ -
Changes in Fair Value Recognized in AOCI	380	118	113	136	(24)	(21)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Electric Generation, Transmission and Distribution Revenues	(251)	(613)	(504)	(759)	-	-
Purchased Electricity for Resale	462	1,126	926	1,394	-	-
Regulatory Assets	1,639	-	163	-	-	-
Regulatory Liabilities	(890)	-	(89)	-	-	-
Ending Balance in AOCI as of March 31, 2009	$ 4,066	$ 2,162	$ 2,091	$ 2,669	$ (24)	$ (21)

Interest Rate and Foreign Currency Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Beginning Balance in AOCI as of January 1, 2009	$ (8,118)	$ -	$ (10,521)	$ 1,752	$ (704)	$ (5,924)
Changes in Fair Value Recognized in AOCI	-	-	-	263	-	(91)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Depreciation and Amortization Expense	-	-	(2)	1	-	-
Interest Expense	416	-	252	23	46	207
Ending Balance in AOCI as of March 31, 2009	$ (7,702)	$ -	$ (10,271)	$ 2,039	$ (658)	$ (5,808)

TOTAL Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Beginning Balance in AOCI as of January 1, 2009	$ (5,392)	$ 1,531	$ (9,039)	$ 3,650	$ (704)	$ (5,924)
Changes in Fair Value Recognized in AOCI	380	118	113	399	(24)	(112)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Electric Generation, Transmission and Distribution Revenues	(251)	(613)	(504)	(759)	-	-
Purchased Electricity for Resale	462	1,126	926	1,394	-	-
Depreciation and Amortization Expense	-	-	(2)	1	-	-
Interest Expense	416	-	252	23	46	207
Regulatory Assets	1,639	-	163	-	-	-
Regulatory Liabilities	(890)	-	(89)	-	-	-
Ending Balance in AOCI as of March 31, 2009	$ (3,636)	$ 2,162	$ (8,180)	$ 4,708	$ (682)	$ (5,829)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets at March 31, 2009 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Condensed Balance Sheets

Company	Hedging Assets (a) Commodity	Hedging Assets (a) Interest Rate and Foreign Currency	Hedging Liabilities (a) Commodity	Hedging Liabilities (a) Interest Rate and Foreign Currency	AOCI Gain (Loss) Net of Tax Commodity	AOCI Gain (Loss) Net of Tax Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ 6,807	$ -	$ (559)	$ -	$ 4,066	$ (7,702)
CSPCo	3,610	-	(288)	-	2,162	-
I&M	3,494	-	(283)	-	2,091	(10,271)
OPCo	4,474	1,328	(371)	(924)	2,669	2,039
PSO	-	-	(33)	-	(24)	(658)
SWEPCo	-	1	(30)	(301)	(21)	(5,808)

Company	Expected to be Reclassified to Net Income During the Next Twelve Months Commodity	Expected to be Reclassified to Net Income During the Next Twelve Months Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$ 3,939	$ (1,670)	14
CSPCo	2,095	-	14
I&M	2,024	(1,007)	14
OPCo	2,586	273	14
PSO	(23)	(183)	10
SWEPCo	(21)	(829	44

(a) Hedging Assets and Hedging Liabilities are in included in Risk Management Assets and Liabilities on the Condensed Balance Sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

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

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

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), the Registrant Subsidiaries are obligated to post an amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, the risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management believes that a downgrade below investment grade is unlikely. The following table represents the Registrant Subsidiaries' aggregate fair value of such contracts, the amount of collateral the Registrant Subsidiaries would have been required to post if the credit ratings had declined below investment grade and how much was attributable to RTO and ISO activities as of March 31, 2009.

Company	Aggregate Fair Value Contracts	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 38,664	$ 38,664	$ 38,220
CSPCo	20,506	20,506	20,270
I&M	19,845	19,845	19,617
OPCo	25,401	25,401	25,110
PSO	5,101	5,101	4,608
SWEPCo	6,012	6,012	5,431

As of March 31, 2009, the Registrant Subsidiaries were not required to post any collateral.

FAIR VALUE MEASUREMENTS

SFAS 157 Fair Value Measurements

As described in the 2008 Annual Report, 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). The Derivatives, Hedging and Fair Value Measurements note within the 2008 Annual Report should be read in conjunction with this report.

The following tables set forth by level within the fair value hierarchy the financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009 and December 31, 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 March 31, 2009

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 421	$ -	$ -	$ 51	$ 472
Risk Management Assets					
Risk Management Contracts (a)	18,217	912,180	16,344	(825,771)	120,970
Cash Flow and Fair Value Hedges (a)	-	8,663	-	(1,856)	6,807
Dedesignated Risk Management Contracts (b)	-	-	-	12,189	12,189
Total Risk Management Assets	18,217	920,843	16,344	(815,438)	139,966
Total Assets	$ 18,638	$ 920,843	$ 16,344	$ (815,387)	$ 140,438
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 20,078	$ 876,231	$ 4,497	$ (836,745)	$ 64,061
Cash Flow and Fair Value Hedges (a)	-	2,415	-	(1,856)	559
DETM Assignment (c)	-	-	-	4,527	4,527
Total Risk Management Liabilities	$ 20,078	$ 878,646	$ 4,497	$ (834,074)	$ 69,147

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

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 656	$ -	$ -	$ 52	$ 708
Risk Management Assets					
Risk Management Contracts (a)	16,105	667,748	11,981	(597,676)	98,158
Cash Flow and Fair Value Hedges (a)	-	6,634	-	(1,413)	5,221
Dedesignated Risk Management Contracts (b)	-	-	-	12,856	12,856
Total Risk Management Assets	16,105	674,382	11,981	(586,233)	116,235
Total Assets	$ 16,761	$ 674,382	$ 11,981	$ (586,181)	$ 116,943
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 18,808	$ 628,974	$ 3,972	$ (601,108)	$ 50,646
Cash Flow and Fair Value Hedges (a)	-	2,545	-	(1,413)	1,132
DETM Assignment (c)	-	-	-	5,230	5,230
Total Risk Management Liabilities	$ 18,808	$ 631,519	$ 3,972	$ (597,291)	$ 57,008

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

CSPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 20,036	$ -	$ -	$ 1,171	$ 21,207
Risk Management Assets					
Risk Management Contracts (a)	9,662	481,211	8,679	(435,732)	63,820
Cash Flow and Fair Value Hedges (a)	-	4,594	-	(984)	3,610
Dedesignated Risk Management Contracts (b)	-	-	-	6,465	6,465
Total Risk Management Assets	9,662	485,805	8,679	(430,251)	73,895
Total Assets	$ 29,698	$ 485,805	$ 8,679	$ (429,080)	$ 95,102
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 10,649	$ 462,306	$ 2,385	$ (441,545)	$ 33,795
Cash Flow and Fair Value Hedges (a)	-	1,272	-	(984)	288
DETM Assignment (c)	-	-	-	2,401	2,401
Total Risk Management Liabilities	$ 10,649	$ 463,578	$ 2,385	$ (440,128)	$ 36,484

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

CSPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 31,129	$ -	$ -	$ 1,171	$ 32,300
Risk Management Assets					
Risk Management Contracts (a)	9,042	366,557	6,724	(328,027)	54,296
Cash Flow and Fair Value Hedges (a)	-	3,725	-	(794)	2,931
Dedesignated Risk Management Contracts (b)	-	-	-	7,218	7,218
Total Risk Management Assets	9,042	370,282	6,724	(321,603)	64,445
Total Assets	$ 40,171	$ 370,282	$ 6,724	$ (320,432)	$ 96,745
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 10,559	$ 344,860	$ 2,227	$ (329,954)	$ 27,692
Cash Flow and Fair Value Hedges (a)	-	1,429	-	(794)	635
DETM Assignment (c)	-	-	-	2,937	2,937
Total Risk Management Liabilities	$ 10,559	$ 346,289	$ 2,227	$ (327,811)	$ 31,264

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

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 9,351	$ 470,390	$ 8,401	$ (425,852)	$ 62,290
Cash Flow and Fair Value Hedges (a)	-	4,446	-	(952)	3,494
Dedesignated Risk Management Contracts (b)	-	-	-	6,256	6,256
Total Risk Management Assets	9,351	474,836	8,401	(420,548)	72,040
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	14,591	-	9,114	23,705
Debt Securities (f)	-	763,963	-	-	763,963
Equity Securities (g)	418,876	-	-	-	418,876
Total Spent Nuclear Fuel and Decommissioning Trusts	418,876	778,554	-	9,114	1,206,544
Total Assets	$ 428,227	$ 1,253,390	$ 8,401	$ (411,434)	$ 1,278,584
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 10,306	$ 451,801	$ 2,309	$ (431,482)	$ 32,934
Cash Flow and Fair Value Hedges (a)	-	1,236	-	(953)	283
DETM Assignment (c)	-	-	-	2,324	2,324
Total Risk Management Liabilities	$ 10,306	$ 453,037	$ 2,309	$ (430,111)	$ 35,541

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

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 8,750	$ 357,405	$ 6,508	$ (319,857)	$ 52,806
Cash Flow and Fair Value Hedges (a)	-	3,605	-	(768)	2,837
Dedesignated Risk Management Contracts (b)	-	-	-	6,985	6,985
Total Risk Management Assets	8,750	361,010	6,508	(313,640)	62,628
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	7,818	-	11,845	19,663
Debt Securities (f)	-	771,216	-	-	771,216
Equity Securities (g)	468,654	-	-	-	468,654
Total Spent Nuclear Fuel and Decommissioning Trusts	468,654	779,034	-	11,845	1,259,533
Total Assets	$ 477,404	$ 1,140,044	$ 6,508	$ (301,795)	$ 1,322,161
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 10,219	$ 336,280	$ 2,156	$ (321,722)	$ 26,933
Cash Flow and Fair Value Hedges (a)	-	1,383	-	(768)	615
DETM Assignment (c)	-	-	-	2,842	2,842
Total Risk Management Liabilities	$ 10,219	$ 337,663	$ 2,156	$ (319,648)	$ 30,390

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

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (e)	$ 1,071	$ -	$ -	$ 1,674	$ 2,745
Risk Management Assets					
Risk Management Contracts (a)	11,968	710,179	10,793	(637,725)	95,215
Cash Flow and Fair Value Hedges (a)	-	7,021	-	(1,219)	5,802
Dedesignated Risk Management Contracts (b)	-	-	-	8,008	8,008
Total Risk Management Assets	11,968	717,200	10,793	(630,936)	109,025
Total Assets	$ 13,039	$ 717,200	$ 10,793	$ (629,262)	$ 111,770
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 13,191	$ 685,375	$ 2,991	$ (644,937)	$ 56,620
Cash Flow and Fair Value Hedges (a)	-	2,514	-	(1,219)	1,295
DETM Assignment (c)	-	-	-	2,975	2,975
Total Risk Management Liabilities	$ 13,191	$ 687,889	$ 2,991	$ (643,181)	$ 60,890

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

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (e)	$ 4,197	$ -	$ -	$ 2,431	$ 6,628
Risk Management Assets					
Risk Management Contracts (a)	11,200	575,415	8,364	(515,162)	79,817
Cash Flow and Fair Value Hedges (a)	-	4,614	-	(983)	3,631
Dedesignated Risk Management Contracts (b)	-	-	-	8,941	8,941
Total Risk Management Assets	11,200	580,029	8,364	(507,204)	92,389
Total Assets	$ 15,397	$ 580,029	$ 8,364	$ (504,773)	$ 99,017
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 13,080	$ 550,278	$ 2,801	$ (517,548)	$ 48,611
Cash Flow and Fair Value Hedges (a)	-	1,770	-	(983)	787
DETM Assignment (c)	-	-	-	3,637	3,637
Total Risk Management Liabilities	$ 13,080	$ 552,048	$ 2,801	$ (514,894)	$ 53,035

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

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 4,031	$ 43,779	$ 11	$ (39,589)	$ 8,232
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,471	$ 41,387	$ 10	$ (39,982)	$ 5,886
Cash Flow Hedges (a)	-	33	-	-	33
DETM Assignment (c)	-	-	-	168	168
Total Risk Management Liabilities	$ 4,471	$ 41,420	$ 10	$ (39,814)	$ 6,087

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

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,295	$ 39,866	$ 8	$ (36,422)	$ 6,747
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 3,664	$ 37,835	$ 10	$ (36,527)	$ 4,982
DETM Assignment (c)	-	-	-	149	149
Total Risk Management Liabilities	$ 3,664	$ 37,835	$ 10	$ (36,378)	$ 5,131

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

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 4,751	$ 64,116	$ 18	$ (57,779)	$ 11,106
Cash Flow and Fair Value Hedges (a)	-	59	-	(58)	1
Total Risk Management Assets	$ 4,751	$ 64,175	$ 18	$ (57,837)	$ 11,107
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 5,270	$ 60,513	$ 16	$ (58,235)	$ 7,564
Cash Flow and Fair Value Hedges (a)	-	389	-	(58)	331
DETM Assignment (c)	-	-	-	198	198
Total Risk Management Liabilities	$ 5,270	$ 60,902	$ 16	$ (58,095)	$ 8,093

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

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,883	$ 61,471	$ 14	$ (55,710)	$ 9,658
Cash Flow and Fair Value Hedges (a)	-	107	-	(80)	27
Total Risk Management Assets	$ 3,883	$ 61,578	$ 14	$ (55,790)	$ 9,685
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,318	$ 58,390	$ 17	$ (55,834)	$ 6,891
Cash Flow and Fair Value Hedges (a)	-	265	-	(80)	185
DETM Assignment (c)	-	-	-	175	175
Total Risk Management Liabilities	$ 4,318	$ 58,655	$ 17	$ (55,739)	$ 7,251

(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 revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 15 in the 2008 Annual Report.

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

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

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

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

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

Three Months Ended March 31, 2009	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of January 1, 2009	$ 8,009	$ 4,497	$ 4,352	$ 5,563	$ (2)	$ (3)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(3,898)	(2,189)	(2,118)	(2,700)	3	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	3,264	-	4,045	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(74)	(42)	(40)	(52)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	7,810	764	3,898	946	-	-
Balance as of March 31, 2009	$ 11,847	$ 6,294	$ 6,092	$ 7,802	$ 1	$ 2

Three Months Ended March 31, 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 Net Income (or Changes in Net Assets) (a)	(657)	(414)	(391)	(176)	29	63
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	721	-	1,639	-	106
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(1,026)	(596)	(572)	(693)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,438	-	724	-	193	204
Balance as of March 31, 2008	$ (942)	$ (552)	$ (519)	$ (837)	$ (21)	$ (35)

(a) Included in revenues on the 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 Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

8. INCOME TAXES

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2000. The Registrant Subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. 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.

9. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2009 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$ 350,000	7.95	2020
I&M	Senior Unsecured Notes	475,000	7.00	2019
I&M	Pollution Control Bonds	50,000	6.25	2025
I&M	Pollution Control Bonds	50,000	6.25	2025
PSO	Pollution Control Bonds	33,700	5.25	2014

Company	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Land Note	$ 4	13.718	2026
OPCo	Notes Payable	1,000	6.27	2009
OPCo	Notes Payable	3,500	7.21	2009
SWEPCo	Notes Payable	1,101	4.47	2011

In January 2009, AEP Parent loaned I&M $25 million of 5.375% Notes Payable due in 2010.

During 2008, the Registrant Subsidiaries chose to begin eliminating their auction-rate debt position due to market conditions. As of March 31, 2009, OPCo had $218 million of tax-exempt long-term debt sold at auction rates (rates at contractual maximum rate of 13%) that reset every 35 days. OPCo’s debt relates to a lease structure with JMG that OPCo is unable to refinance without their consent. The initial term for the JMG lease structure matures on March 31, 2010 and management is evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO. As of March 31, 2009, SWEPCo had $53.5 million of tax-exempt long-term debt sold at auction rates (rate of 1.676%) that reset every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures.

During the first quarter of 2009, I&M and PSO issued $100 million of 6.25% Pollution Control Bonds due in 2025 and $33.7 million of 5.25% Pollution Control Bonds due in 2014, respectively, which were previously held by trustees on the Registrant Subsidiaries’ behalf. As of March 31, 2009, trustees held, on the Registrant Subsidiaries’ behalf, $195 million of the remaining reacquired auction-rate tax-exempt long-term debt which the Registrant Subsidiaries plan to reissue to the public as market conditions permit.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool 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 March 31, 2009 and December 31, 2008 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 three months ended March 31, 2009 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 March 31, 2009	Authorized Short-Term Borrowing Limit
			(in thousands)			
APCo	$ 420,925	$ -	$ 248,209	$ -	$ (120,481)	$ 600,000
CSPCo	203,306	-	135,532	-	(177,736)	350,000
I&M	491,107	22,979	153,707	16,201	(16,421)	500,000
OPCo	406,354	-	281,950	-	(320,166)	600,000
PSO	77,976	87,443	58,549	46,483	7,009	300,000
SWEPCo	62,871	63,539	30,880	29,381	37,649	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Three Months Ended March 31,	
	2009	2008
Maximum Interest Rate	2.28%	5.37%
Minimum Interest Rate	1.22%	3.39%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 2009 and 2008 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Three Months Ended March 31,		Average Interest Rate for Funds Loaned to the Utility Money Pool for the Three Months Ended March 31,	
Company	2009	2008	2009	2008
APCo	1.76%	4.21%	-%	3.46%
CSPCo	1.62%	4.01%	-%	-%
I&M	1.86%	3.99%	1.76%	-%
OPCo	1.65%	4.29%	-%	-%
PSO	2.01%	3.51%	1.63%	4.57%
SWEPCo	1.86%	4.00%	1.68%	-%

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		March 31, 2009		December 31, 2008	
Company	Type of Debt	Outstanding Amount (in thousands)	Weighted Average Interest Rate	Outstanding Amount (in thousands)	Weighted Average Interest Rate
SWEPCo	Line of Credit – Sabine Mining Company (a)	$ 6,559	1.82%	$ 7,172	1.54%

(a) Sabine Mining Company is consolidated under FIN 46R.

Credit Facilities

The Registrant Subsidiaries and certain other companies in the AEP System have 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. In April 2009, the $350 million 364-day credit agreement expired. As of March 31, 2009, $372 million letters of credit were issued by Registrant Subsidiaries under the $650 million 3-year credit agreement to support variable rate Pollution Control Bonds as follow:

Company	Letters of Credit Amount Outstanding Against $650 million 3-Year Agreement (in thousands)
APCo	$ 126,716
I&M	77,886
OPCo	166,899

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and 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 2008 Annual Report should also be read in conjunction with this report.

Economic Slowdown

The financial struggles of the U.S. economy continue to impact the Registrant Subsidiaries' industrial sales as well as sales opportunities in the wholesale market. Industrial sales in various sections of the service territories are decreasing due to reduced shifts and suspended operations by some of the Registrant Subsidiaries' large industrial customers. Although many sections of the Registrant Subsidiaries' service territories are experiencing slowdowns in new construction, their residential and commercial customer base appears to be stable. As a result of these economic issues, management is currently monitoring the following:

- Margins from Off-system Sales – Margins from off-system sales for the AEP System continue to decrease due to reductions in sales volumes and weak market power prices, reflecting reduced overall demand for electricity. Management currently forecasts that margins from off-system volumes will decrease by approximately 30% in 2009. These trends will most likely continue until the economy rebounds and electricity demand and prices increase.

- Industrial KWH Sales – The AEP System's industrial KWH sales for the quarter ended March 31, 2009 were down 15% in comparison to the quarter ended March 31, 2008. Approximately half of this decrease was due to cutbacks or closures by customers who produce primary metals served by APCo, CSPCo, I&M, OPCo and SWEPCo. I&M, PSO and SWEPCo also experienced additional significant decreases in KWH sales to customers in the plastics, rubber and paper manufacturing industries. Since the AEP System's trends for industrial sales are usually similar to the nation's industrial production, these trends will continue until industrial production improves.

- Risk of Loss of Major Customers – Management monitors the financial strength and viability of each major industrial customer individually. The Registrant Subsidiaries have factored this analysis into their operational planning. CSPCo's and OPCo's largest customer, Ormet, with a 520 MW load, recently announced that it is in dispute with its sole customer which could potentially force Ormet to halt production. In February 2009, Century Aluminum, a major industrial customer (325 MW load) of APCo, announced the curtailment of operations at its Ravenswood, WV facility.

Credit Markets

The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact the Registrant Subsidiaries' access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications since the Registrant Subsidiaries rely on continuing access to capital to fund operations and capital expenditures.

Management believes that the Registrant Subsidiaries have adequate liquidity, through the Utility Money Pool and cash flows from their operations, to support planned business operations and capital expenditures through 2009. To support operations, AEP has $3.9 billion in aggregate credit facility commitments as of March 31, 2009. These commitments include 27 different banks with no one bank having more than 10% of the total bank commitments. Short-term funding for the Registrant Subsidiaries comes from AEP's credit facilities which support the Utility Money Pool. APCo, OPCo and PSO have $150 million, $73 million and $50 million, respectively, maturing in the remainder of 2009. Long-term debt of $200 million, $150 million, $680 million and $150 million will mature in 2010 for APCo, CSPCo, OPCo and PSO, respectively. Management intends to refinance debt maturities. 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.

AEP sponsors several trust funds with significant investments intended to provide for future payments of pensions and OPEB. I&M has significant investments in several trust funds intended to provide for future payments of nuclear decommissioning and spent nuclear fuel disposal. Although 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 declined substantially over the past year due to decreases in domestic and international equity markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. The decline in pension asset values will not require the AEP System to make a contribution under ERISA in 2009. As of March 31, 2009, management estimates that the minimum contributions to the pension trust will be $475 million in 2010 and $283 million in 2011. These amounts are allocated to companies in the AEP System, including the Registrant Subsidiaries. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

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.

Budgeted Construction Expenditures

Budgeted construction expenditures for the Registrant Subsidiaries for 2010 are:

Company	Budgeted Construction Expenditures (in millions)
APCo	$ 297
CSPCo	231
I&M	246
OPCo	294
PSO	162
SWEPCo	423

Budgeted 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.

LIQUIDITY

Sources of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program and revolving credit facilities through the Utility Money Pool. AEP and its Registrant Subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity. 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). 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-leasebacks, leasing arrangements and additional capital contributions from Parent.

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. Management chose to allow the $350 million credit agreement to expire in April 2009. The Registrant Subsidiaries may issue LOCs under the credit facility. Each subsidiary has a borrowing/LOC limit under the credit facility. As of March 31, 2009, 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 the credit facility and the outstanding amount of LOCs.

Company	$650 million Credit Facility Borrowing/LOC Limit	LOC Amount Outstanding Against $650 million Agreement at March 31, 2009
	(in millions)	
APCo	$ 300	$ 127
CSPCo	230	-
I&M	230	78
OPCo	400	167
PSO	65	-
SWEPCo	230	-

Dividend Restrictions

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital.

Sale of Receivables Through AEP Credit

In 2008, AEP Credit renewed its sale of receivables agreement through October 2009. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Management intends to extend or replace the sale of receivables agreement. At March 31, 2009, $578 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit purchases accounts receivable from the Registrant Subsidiaries.

SIGNIFICANT FACTORS

Ohio Electric Security Plan Filings

In March 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs which will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the fuel adjustment clause (FAC). The ordered increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. After final PUCO review and approval of conforming rate schedules, CSPCo and OPCo implemented rates for the April 2009 billing cycle. CSPCo and OPCo will collect the 2009 annualized revenue increase over the remainder of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. As of March 31, 2009, the FAC deferral balances were $17 million and $66 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales. In addition, the ESP order provided for both the FAC deferral credits and the off-system sales margins to be excluded from the methodology for the Significantly Excessive Earnings Test (SEET). The SEET is discussed below.

Additionally, the order addressed several other items, including:

- The approval of new distribution riders, subject to true-up for recovery of costs for enhanced vegetation management programs for CSPCo and OPCo and the proposed gridSMART advanced metering initial program roll out in a portion of CSPCo's service territory. The PUCO proposed that CSPCo mitigate the costs of gridSMART by seeking matching funds under the American Recovery and Reinvestment Act of 2009. As a result, a rider was established to recover 50% or $32 million of the projected $64 million revenue requirement related to gridSMART costs. The PUCO denied the other distribution system reliability programs proposed by CSPCo and OPCo as part of their ESP filings. The PUCO decided that those requests should be examined in the context of a complete distribution base rate case. The order did not require CSPCo and/or OPCo to file a distribution base rate case.

- The approval of CSPCo's and OPCo's request to recover the incremental carrying costs related to environmental investments made from 2001 through 2008 that are not reflected in existing rates. Future recovery during the ESP period of incremental carrying charges on environmental expenditures incurred beginning in 2009 may be requested in annual filings.

- The approval of a $97 million and $55 million increase in CSPCo's and OPCo's Provider of Last Resort charges, respectively, to compensate for the risk of customers changing electric suppliers during the ESP period.

- The requirement that CSPCo's and OPCo's shareholders fund a combined minimum of $15 million in costs over the ESP period for low-income, at-risk customer programs. This funding obligation was recognized as a liability and an unfavorable adjustment to Other Operation and Maintenance expense for the three-month period ending March 31, 2009.

- The deferral of CSPCo's and OPCo's request to recover certain existing regulatory assets, including customer choice implementation and line extension carrying costs as part of the ESPs. The PUCO decided it would be more appropriate to consider this request in the context of CSPCo's and OPCo's next distribution base rate case. These regulatory assets, which were approved by prior PUCO orders, total $58 million for CSPCo and $40 million for OPCo as of March 31, 2009. In addition, CSPCo and OPCo would recover and recognize as income, when collected, $35 million and $26 million, respectively, of related unrecorded equity carrying costs incurred through March 2009.

Finally, consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the SEET that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings as measured by whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that have comparable business and financial risk. If the rate adjustments, in the aggregate, result in significantly excessive earnings in comparison, the PUCO must require that the amount of the excess be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until the second or third quarter of 2010.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP, not to the effective date of tariffs and clarified the tariffs were not retroactive. In March 2009, CSPCo and OPCo implemented the new ESP tariffs effective with the start of the April 2009 billing cycle. In April 2009, CSPCo and OPCo filed a motion requesting rehearing of several issues. In April 2009, several intervenors filed motions requesting rehearing of issues underlying the PUCO's authorized rate increases and one intervenor filed a motion requesting the PUCO to direct CSPCo and OPCo to cease collecting rates under the order. Certain intervenors also filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases.

Management will evaluate whether it will withdraw the ESP applications after a final order, thereby terminating the ESP proceedings. If CSPCo and/or OPCo withdraw the ESP applications, CSPCo and/or OPCo may file a Market Rate Offer (MRO) or another ESP as permitted by the law. The revenues collected and recorded in 2009 under this PUCO order are subject to possible refund through the SEET process. Management is unable, due to the decision of the PUCO to defer guidance on the SEET methodology to a future generic SEET proceeding, to estimate the amount, if any, of a possible refund that could result from the SEET process in 2010.

New Generation/Purchase Power Agreement

In 2009, AEP 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)				
AEGCo	Dresden	(c)	Ohio	$ 322	$ 189	Gas	Combined-cycle	580	2013
SWEPCo	Stall		Louisiana	385	291	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(d)	Arkansas	1,628(d)	480	Coal	Ultra-supercritical	600(d)	2012
APCo	Mountaineer	(e)	West Virginia	(e)		Coal	IGCC	629	(e)
CSPCo/OPCo	Great Bend	(e)	Ohio	(e)		Coal	IGCC	629	(e)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) 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.
(d) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. See "Turk Plant" section below.
(e) Construction of IGCC plants is subject to regulatory approvals. See "IGCC Plants" section below.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners have appealed the APSC's decision 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 previously estimated $1.522 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. 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 effect 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.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. 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 2009, SWEPCo filed a motion to dismiss the appeal. In March 2009, the motion was granted.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant's permit is heard. Hearings on the air permit appeal are scheduled for June 2009. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers a potential wetlands impact on approximately 2.5 acres at the Turk Plant. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas of the Turk Plant. The impact on the construction schedule and workforce is currently being evaluated by management.

In January and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications 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. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor's Commission on Global Warming issued its final report to the Governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build and operate 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 costs incurred plus related shutdown costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of March 31, 2009, SWEPCo has capitalized approximately $480 million of expenditures (including AFUDC) and has contractual construction commitments for an additional $655 million. As of March 31, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $100 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.

IGCC Plants

The construction of the West Virginia and Ohio IGCC plants are pending regulatory approvals. In April 2008, the Virginia SCC issued an order denying 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. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. 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 March 2009, APCo deferred for future recovery preconstruction IGCC costs of $20 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, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. However, 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 pre-construction 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.

PSO Purchase Power Agreement

PSO and Exelon Generation Company LLC, a subsidiary of Exelon Corporation, executed a long-term purchase power agreement (PPA) for which an application seeking its approval is expected to be filed with the OCC. The PPA is for the purchase of up to 520 MW of electric generation from the 795 MW natural gas-fired Green Country Generating Station, located in Jenks, Oklahoma. The agreement is the result of PSO's 2008 Request for Proposals following a December 2007 OCC order that found PSO had a need for new baseload generation by 2012.

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, particulate matter (PM) and mercury from fossil fuel-fired power plants; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain 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 involved in the development of possible future requirements to reduce CO_2 and other greenhouse gases (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 2008 Annual Report.

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 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. The Registrant Subsidiaries sought further review and filed for relief from the schedules included in their permits.

In April 2009, the U.S. Supreme Court issued a decision that allows the Federal EPA the discretion to rely on cost-benefit analysis in setting national performance standards and in providing for cost-benefit variances from those standards as part of the regulations. Management cannot predict if or how the Federal EPA will apply this decision to any revision of the regulations or what effect it may have on similar requirements adopted by the states.

Potential Regulation of CO_2 and Other GHG Emissions

As discussed in the 2008 Annual Report, CO_2 and other GHG are alleged to contribute to climate change. In April 2009, the Federal EPA issued a proposed endangerment finding under the CAA regarding GHG emissions from motor vehicles. The proposed endangerment finding is subject to public comment. This finding could lead to regulation of CO_2 and other gases under existing laws. Congress continues to discuss new legislation related to the control of these emissions. Some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including the AEP System. Because of these adverse consequences, management believes that these more extreme policies will not ultimately be adopted. Even if reasonable CO_2 and other GHG emission standards are imposed, they will still require the

Registrant Subsidiaries to make material expenditures. Management believes that costs of complying with new CO_2 and other GHG emission standards will be treated like all other reasonable costs of serving customers, and should be recoverable from customers as costs of doing business including capital investments with a return on investment.

Adoption of New Accounting Pronouncements

The FASB issued SFAS 141R (revised "Business Combinations" 2007) improving financial reporting about business combinations and their effects. SFAS 141R can affect tax positions on previous acquisitions. The Registrant Subsidiaries do not have any such tax positions that result in adjustments. The Registrant Subsidiaries adopted SFAS 141R effective January 1, 2009. The Registrant Subsidiaries will apply it to any future business combinations.

The FASB issued SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. The Registrant Subsidiaries adopted SFAS 160 retrospectively effective January 1, 2009. See Note 2.

The FASB issued SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161), enhancing disclosure requirements for derivative instruments and hedging activities. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard increased disclosure requirements related to derivative instruments and hedging activities in future reports. The Registrant Subsidiaries adopted SFAS 161 effective January 1, 2009.

The FASB ratified EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5) a 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. The Registrant Subsidiaries adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability.

The FASB ratified EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6), a consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. The Registrant Subsidiaries prospectively adopted EITF 08-6 effective January 1, 2009 with no impact on their financial statements.

The FASB issued FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The Registrant Subsidiaries adopted the rule effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

The FASB issued 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). 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. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals. The Registrant Subsidiaries adopted SFAS 157-2 effective January 1, 2009. The Registrant Subsidiaries will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. The Registrant Subsidiaries did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first quarter of 2009.

CONTROLS AND PROCEDURES

During the first quarter of 2009, 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 March 31, 2009 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 first quarter of 2009 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 "Commitments, Guarantees and Contingencies" section of Note 4 incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2008 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 2008 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Rate recovery approved in Ohio may be overturned on appeal. *(Applies to AEP, OPCo and CSPCo)*

In March 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the FAC. The ordered rate cap increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. In April 2009, several intervenors filed motions requesting rehearing of issues underlying the PUCO's authorized rate increase and one intervenor filed a motion requesting the PUCO to direct CSPCo and OPCo to cease collecting rates under the order. Certain intervenors also filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increase. If the PUCO reverses all or part of the rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Rate recovery approved in Texas may be overturned on appeal. *(Applies to AEP)*

In March 2008, the PUCT issued an order approving a $20 million base rate increase based on a return on common equity of 9.96% and an additional $20 million increase in revenues related to the expiration of TCC's merger credits. In addition, depreciation expense was decreased by $7 million and discretionary fee revenues were increased by $3 million. TCC estimates the order will increase TCC's annual pretax income by $50 million. Various parties appealed the PUCT decision.

In February 2009, the Texas District Court affirmed the PUCT in most respects. In March 2009, various intervenors appealed the Texas District Court decision to the Texas Court of Appeals. Management is unable to predict the outcome of these proceedings. If the PUCT and/or the Texas Court of Appeals reverse all or part of the rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Rate recovery approved in Oklahoma may be overturned on appeal. *(Applies to AEP and PSO)*

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues and a 10.5% return on equity. In February 2009, the Oklahoma Attorney General and several intervenors filed appeals with the Oklahoma Supreme Court raising several issues. If the OCC and/or the Oklahoma Supreme Court reverse all or part of the rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Our request for rate recovery in Arkansas may not be approved in its entirety. *(Applies to SWEPCo)*

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to concurrently recover financing costs related to the Stall and Turk construction projects. If the APSC 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 Market, Economic or Financial Volatility

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 2009, Fitch downgraded the senior unsecured debt rating of I&M to BBB with stable outlook.

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.

Risks Relating to State Restructuring

There is uncertainty related to Texas restructuring. *(Applies to SWEPCo)*

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In April 2009, the Texas Senate passed a bill related to SWEPCo's SPP area of Texas that requires cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all retail customer classes. The bill is expected to be reviewed by the Texas House of Representatives which, if passed, would be sent to the Governor of Texas for approval. If the bill is signed, management may be required to re-apply SFAS 71 for the generation portion of SWEPCo's Texas jurisdiction. The initial reapplication of SFAS 71 regulatory accounting is expected to have a material adverse effect on net income.

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 March 31, 2009 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
01/01/09 – 01/31/09	-	$ -	-	$ -
02/01/09 – 02/28/09	35(a)	65.03	-	-
03/01/09 – 03/31/09	-	-	-	-

(a) I&M repurchased 34 shares of its 4.125% cumulative preferred stock in a privately-negotiated transaction outside of an announced program. OPCo repurchased 1 share of its 4.50% cumulative preferred stock in a privately-negotiated transaction outside of an announced program.

Item 5. <u>Other Information</u>

NONE

Item 6. <u>Exhibits</u>

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: May 1, 2009