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

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

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

Yes _X_ *No* ___

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

Large accelerated filer _X_ *Accelerated filer* ___

Non-accelerated filer ____ *Smaller reporting company* ___

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

Large accelerated filer ____ *Accelerated filer* ___

Non-accelerated filer _X_ *Smaller reporting company* ___

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

Yes ___ *No* _X_

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

	Number of shares of common stock outstanding of the registrants at July 31, 2008
American Electric Power Company, Inc.	402,258,849 ($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
June 30, 2008

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
E&R	Environmental compliance and transmission and distribution system reliability.
EaR	Earnings at Risk, a method to quantify risk exposure.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
EPS	Earnings Per Share.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
FSP	FASB Staff Position.
FTR	Financial Transmission Right.
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company, a former AEP subsidiary.

Term	Meaning
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over-the-counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RSP	Rate Stabilization Plan.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."

Term	Meaning
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.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP. AEP's 50% interest in Sweeny was sold in October 2007.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading 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 RTOs.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

EXECUTIVE OVERVIEW

Base Rate Filings

Our significant base rate filings include:

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

(a) Subject to refund.
(b) Net of estimated amounts that PSO expects to recover through a generation cost recovery rider which will terminate upon implementation of the new base rates.

Ohio Electric Security Plan Filings

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

Turk Plant

In July 2008, the PUCT approved a certificate of convenience and necessity for construction of the plant. We expect a written order in August 2008 which will also provide for the conditions of the PUCT's approval. SWEPCo has received approvals from all of the state commissions that regulate its retail rates and services. However, the APSC approval has been appealed to the Arkansas State Court of Appeals. SWEPCo is working with the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers for approval later this year. Through June 30, 2008, SWEPCo capitalized $407 million in expenditures related to the Turk Plant.

IGCC Plants

We have delayed construction of the West Virginia and Ohio IGCC plants. In May 2008, the Virginia SCC denied APCo's request to reconsider the Virginia SCC's previous denial of APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. In Ohio, CSPCo and OPCo await the result of an Ohio Supreme Court remand to the PUCO regarding recovery of IGCC pre-construction costs.

Fuel Costs

We currently estimate 2008 coal prices to increase by about 20% due to escalating domestic prices and increased needs, primarily in the east. We had expected coal costs to increase by 13% in 2008. We continue to see increases in prices due to expiring lower priced coal and transportation contracts being replaced with higher priced contracts. Prices for fuel oil are at record highs and remain volatile. We have limited exposure to price risk related to our open positions for coal, natural gas and fuel oil especially since we do not currently have an active fuel cost recovery adjustment mechanism in Ohio, which represents approximately 20% of our fuel costs. However, under Ohio's amended restructuring law, we have requested the PUCO to reinstate a fuel cost recovery mechanism effective January 1, 2009. Fuel cost adjustment rate clauses in our other jurisdictions will help offset future negative impacts of fuel price increases on our gross margins.

Capital Expenditures

We reduced our projections for capital expenditures to approximately $6.75 billion from $7.35 billion for 2009 through 2010.

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.

MEMCO Operations

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

Generation and Marketing

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

The table below presents our consolidated Income Before Discontinued Operations and Extraordinary Loss by segment for the three and six months ended June 30, 2008 and 2007.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Utility Operations	$ 263	$ 238	$ 673	$ 491
MEMCO Operations	3	7	10	22
Generation and Marketing	26	15	27	14
All Other (a)	(12)	(3)	143	1
Income Before Discontinued Operations and Extraordinary Loss	$ 280	$ 257	$ 853	$ 528

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually liquidate and completely expire in 2011.
- The first quarter 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The cash settlement of $255 million ($163 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP Consolidated

Second Quarter of 2008 Compared to Second Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $23 million compared to 2007 primarily due to an increase in Utility Operations segment earnings of $25 million. The increase in Utility Operations segment earnings primarily relates to rate increases implemented since the second quarter of 2007 in Ohio, Virginia, West Virginia, Texas and Oklahoma, higher off-system sales and unfavorable regulatory provisions recorded in the prior year related to our Virginia and Texas jurisdictions, partially offset by higher operation and maintenance expenses system-wide and higher fuel expenses in Ohio.

Average basic shares outstanding increased to 402 million in 2008 from 399 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 402 million as of June 30, 2008.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $325 million compared to 2007 primarily due to an increase in Utility Operations segment earnings of $182 million and income of $163 million (net of tax) 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. The increase in Utility Operations segment earnings primarily relates to rate increases implemented since the second quarter of 2007 in Ohio, Virginia, West Virginia, Texas and Oklahoma, higher off-system sales and lower operation and maintenance expenses as a result of a favorable Oklahoma ice storm settlement partially offset by higher interest expense.

Average basic shares outstanding increased to 401 million in 2008 from 398 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 402 million as of June 30, 2008.

Utility Operations

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

Utility Operations Income Summary
For the Three and Six Months Ended June 30, 2008 and 2007

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Revenues	$ 3,313	$ 2,954	$ 6,607	$ 5,987
Fuel and Purchased Power	1,374	1,109	2,587	2,228
Gross Margin	1,939	1,845	4,020	3,759
Depreciation and Amortization	365	365	720	748
Other Operating Expenses	1,026	957	1,967	1,948
Operating Income	548	523	1,333	1,063
Other Income, Net	47	27	89	45
Interest Charges and Preferred Stock Dividend Requirements	218	207	428	386
Income Tax Expense	114	105	321	231
Income Before Discontinued Operations and Extraordinary Loss	$ 263	$ 238	$ 673	$ 491

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three and Six Months Ended June 30, 2008 and 2007

Energy/Delivery Summary	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in millions of KWH)			
Energy				
Retail:				
Residential	9,829	10,127	24,329	24,267
Commercial	9,909	10,227	19,456	19,586
Industrial	15,060	14,848	29,410	28,413
Miscellaneous	639	632	1,248	1,245
Total Retail	35,437	35,834	74,443	73,511
Wholesale	10,932	9,376	22,597	18,154
Delivery				
Texas Wires – Energy delivered to customers served by AEP's Texas Wires Companies	7,132	6,746	12,955	12,577
Total KWHs	53,501	51,956	109,995	104,242

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

Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Six Months Ended June 30, 2008 and 2007

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in degree days)			
Weather Summary				
Eastern Region				
Actual – Heating (a)	136	222	1,960	2,039
Normal – Heating (b)	175	174	1,943	1,966
Actual – Cooling (c)	272	367	272	382
Normal – Cooling (b)	278	275	281	278
Western Region (d)				
Actual – Heating (a)	40	92	989	994
Normal – Heating (b)	35	33	966	991
Actual – Cooling (c)	675	622	700	678
Normal – Cooling (b)	652	656	672	674

(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.

Second Quarter of 2008 Compared to Second Quarter of 2007

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

Second Quarter of 2007		$ 238
Changes in Gross Margin:		
Retail Margins	47	
Off-system Sales	40	
Transmission Revenues	11	
Other Revenues	(4)	
Total Change in Gross Margin		94
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(70)	
Depreciation and Amortization	-	
Taxes Other Than Income Taxes	(1)	
Carrying Costs Income	10	
Interest Income	6	
Other Income, Net	6	
Interest and Other Charges	(11)	
Total Change in Operating Expenses and Other		(60)
Income Tax Expense		(9)
Second Quarter of 2008		$ 263

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $25 million to $263 million in 2008. The key drivers of the increase were a $94 million increase in Gross Margin offset by a $60 million increase in Operating Expenses and Other and a $9 million increase in Income Tax Expense.

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

- Retail Margins increased $47 million primarily due to the following:
  - A $39 million increase related to net rate increases implemented in our Ohio jurisdictions, a $17 million increase related to recovery of E&R costs in Virginia and the construction financing costs rider in West Virginia, a $3 million increase in base rates in Texas and a $6 million increase in base rates in Oklahoma.
  - A $38 million net increase due to adjustments recorded in the prior year related to the 2007 Virginia base rate case which included a second quarter 2007 provision for revenue refund.
  - A $25 million increase due to a second quarter 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding.
  - A $12 million increase related to increased usage by Ormet, an industrial customer in Ohio. See “Ormet” section of Note 3.
  - An $11 million increase primarily related to higher revenues under formula rate plans at I&M.

  These increases were partially offset by:
  - A $90 million decrease related to increased fuel, consumable and PJM costs in Ohio which included a $29 million expense resulting from a coal contract amendment.
  - A $20 million decrease in usage related to weather primarily from a 26% decrease in cooling degree days and a 39% decrease in heating degree days in our eastern region.
- Margins from Off-system Sales increased $40 million primarily due to higher east physical off-system sales margins mostly due to higher volumes and stronger prices, partially offset by lower trading margins.
- Transmission Revenues increased $11 million primarily due to increased usage in the SPP and ERCOT regions and increased rates in the SPP region.

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

- Other Operation and Maintenance expenses increased $70 million primarily due to increases in generation expenses for non-outage maintenance at Cook plant and outage expenses at other plants, transmission reliability expenses, recoverable PJM and customer account expenses in Ohio and administrative and general expenses primarily related to employee benefits.
- Depreciation and Amortization expense was flat primarily due to lower commission-approved depreciation rates in Indiana, Michigan, Oklahoma and Texas and lower Ohio regulatory asset amortization, offset by higher depreciable property balances and prior year adjustments related to the 2007 Virginia base rate case.
- Carrying Costs Income increased $10 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.
- Interest and Other Charges increased $11 million primarily due to additional debt issued and higher interest rates on variable rate debt.
- Income Tax Expense increased $9 million due to an increase in pretax income.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

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

Six Months Ended June 30, 2007		$ 491
Changes in Gross Margin:		
Retail Margins	162	
Off-system Sales	80	
Transmission Revenues	19	
Total Change in Gross Margin		261
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	11	
Gain on Dispositions of Assets, Net	(19)	
Depreciation and Amortization	28	
Taxes Other Than Income Taxes	(11)	
Carrying Costs Income	19	
Interest Income	17	
Other Income, Net	8	
Interest and Other Charges	(42)	
Total Change in Operating Expenses and Other		11
Income Tax Expense		(90)
Six Months Ended June 30, 2008		$ 673

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $182 million to $673 million in 2008. The key drivers of the increase were a $261 million increase in Gross Margin and an $11 million decrease in Operating Expenses and Other offset by a $90 million increase in Income Tax Expense.

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

- Retail Margins increased $162 million primarily due to the following:
  - An $83 million increase related to net rate increases implemented in our Ohio jurisdictions, a $31 million increase related to recovery of E&R costs in Virginia and the construction financing costs rider in West Virginia, a $12 million increase in base rates in Texas and a $14 million increase in base rates in Oklahoma.
  - A $33 million increase related to increased usage by Ormet, an industrial customer in Ohio. See "Ormet" section of Note 3.
  - A $29 million increase related to coal contract amendments in 2008.
  - A $28 million increase related to increased residential and commercial usage and customer growth.
  - A $25 million increase due to a second quarter 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding.
  - A $21 million increase related to increased sales to municipal, cooperative and other customers primarily a result of new power supply contracts and higher revenues under formula rate plans at I&M.

  These increases were partially offset by:
  - A $79 million decrease related to increased fuel, consumable and PJM costs in Ohio.
  - A $23 million decrease in usage related to weather primarily from a 29% decrease in cooling degree days in our eastern region.
- Margins from Off-system Sales increased $80 million primarily due to higher east physical off-system sales margins mostly due to higher volumes and stronger prices, partially offset by lower trading margins.
- Transmission Revenues increased $19 million primarily due to increased usage in the SPP and ERCOT regions and increased rates in the SPP region.

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

- Other Operation and Maintenance expenses decreased $11 million primarily due to deferral of storm restoration costs, net of amortization, of $63 million in Oklahoma as a result of a rate settlement to recover 2007 storm restoration costs partially offset by an increase in generation expenses at Cook plant, the write-off of unrecoverable pre-construction costs for PSO's canceled Red Rock Generating Facility, recoverable PJM and customer account expenses in Ohio and increases in administrative and general expenses primarily related to employee benefits.
- Gain on Disposition of Assets, Net decreased $19 million primarily due to the cessation of the earnings sharing agreement with Centrica from the sale of our Texas REPs in 2002. In 2007, we received the final earnings sharing payment of $20 million.
- Depreciation and Amortization expense decreased $28 million primarily due to lower commission-approved depreciation rates in Indiana, Michigan, Oklahoma and Texas and lower Ohio regulatory asset amortization, partially offset by higher depreciable property balances and prior year adjustments related to the Virginia base rate case.
- Taxes Other Than Income Taxes increased $11 million primarily due to favorable adjustments to property tax returns recorded in the prior year.
- Carrying Costs Income increased $19 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.
- Interest Income increased $17 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Interest and Other Charges increased $42 million primarily due to additional debt issued and higher interest rates on variable rate debt.
- Income Tax Expense increased $90 million due to an increase in pretax income.

MEMCO Operations

Second Quarter of 2008 Compared to Second Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss from our MEMCO Operations segment decreased to $3 million in 2008 from $7 million in 2007 primarily due to high water conditions and reduced northbound loadings. Fuel consumption and other operating costs were higher due to the sustained high water conditions on all major rivers on which we operate. Northbound loadings continue to be depressed as a result of reduced imports through the Gulf of Mexico.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from our MEMCO Operations segment decreased to $10 million in 2008 from $22 million in 2007 primarily due to high water conditions and reduced northbound loadings. Fuel consumption and other operating costs were higher due to the sustained high water conditions on all major rivers on which we operate. Northbound loadings continue to be depressed as a result of reduced imports through the Gulf of Mexico.

Generation and Marketing

Second Quarter of 2008 Compared to Second Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased to $26 million in 2008 from $15 million in 2007 primarily due to favorable marketing contracts in ERCOT, higher gross margins at the Oklaunion plant from optimization activities and an increase in income from wind farm operations.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased to $27 million in 2008 from $14 million in 2007 primarily due to favorable marketing contracts in ERCOT, higher gross margins at the Oklaunion plant from optimization activities and an increase in income from wind farm operations.

All Other

Second Quarter of 2008 Compared to Second Quarter of 2007

Loss Before Discontinued Operations and Extraordinary Loss from All Other increased to $12 million in 2008 from $3 million in 2007. The increase in the loss primarily relates to lower cash balances yielding lower interest income and higher interest expense due to the AEP Junior Subordinated Debentures issued in March 2008 and increased short-term borrowings.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from All Other increased to $143 million in 2008 from $1 million in 2007. In 2008, we had after-tax income of $163 million from a litigation settlement of a power purchase and sale agreement with TEM 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 Items of $255 million in the accompanying Condensed Consolidated Statements of Income. In 2007, we had a $16 million pretax gain ($10 million, net of tax) on the sale of a portion of our investment in Intercontinental Exchange, Inc. (ICE).

AEP System Income Taxes

Income Tax Expense increased $15 million in the second quarter of 2008 compared to the second quarter of 2007 primarily due to an increase in pretax income.

Income Tax Expense increased $178 million in the six-month period ended June 30, 2008 compared to the six-month period ended June 30, 2007 primarily due to an increase in pretax income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	June 30, 2008		December 31, 2007	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 15,753	58.0%	$ 14,994	58.1%
Short-term Debt	705	2.6	660	2.6
Total Debt	16,458	60.6	15,654	60.7
Common Equity	10,631	39.2	10,079	39.1
Preferred Stock	61	0.2	61	0.2
Total Debt and Equity Capitalization	$ 27,150	100.0%	$ 25,794	100.0%

Our ratio of debt to total capital decreased from 60.7% to 60.6% in 2008 due to our net earnings and increased common equity from stock issuances through stock compensation and dividend reinvestment plans.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements and common stock.

Credit Markets

We believe we have adequate liquidity under our credit facilities and the ability to issue long-term debt in the current credit markets. As of June 30, 2008, we had $313 million outstanding of tax-exempt long-term debt sold at auction rates that reset every 35 days. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation and Financial Guaranty Insurance Co. Due to the exposure that these bond insurers have in connection with developments in the subprime credit market, the credit ratings of these insurers have been downgraded or placed on negative outlook. These market factors have contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including many of the auctions of our tax-exempt long-term debt. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. Through June 30, 2008, we reduced our outstanding auction rate securities by $1.2 billion. We plan to continue the conversion and refunding process for the remaining $313 million to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, during the second half of 2008 to lower our interest rates as such opportunities arise.

As of June 30, 2008, $367 million of the prior auction rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 1.45% to 1.68% and $384 million was issued at fixed rates ranging from 4.85% to 5.625%. As of June 30, 2008, trustees held, on our behalf, approximately $400 million of our reacquired auction rate tax-exempt long-term debt which we plan to reissue to the public as market conditions permit.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At June 30, 2008, our available liquidity was approximately $3.1 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,500	April 2012
Revolving Credit Facility	650	April 2011
Revolving Credit Facility	350	April 2009
Total	4,000	
Cash and Cash Equivalents	218	
Total Liquidity Sources	4,218	
Less: AEP Commercial Paper Outstanding	698	
Letters of Credit Drawn	429	
Net Available Liquidity	$ 3,091	

The revolving credit facilities for commercial paper backup are structured as two $1.5 billion credit facilities. In March 2008, the credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit.

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of June 30, 2008, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during the first six months of 2008 was $1.2 billion. The weighted-average interest rate of our commercial paper during the first six months of 2008 was 3.22%.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. Under the facilities, we may issue letters of credit. As of June 30, 2008, $371 million of letters of credit were issued under the 3-year credit agreement to support variable rate demand notes.

Investments in Auction-Rate Securities

During the first six months of 2008, we sold all of our investment in auction-rate securities at par.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements, including the new agreements entered into in April 2008, contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At June 30, 2008, this contractually-defined percentage was 55.9%. Nonperformance of these covenants could result in an event of default under these credit agreements. At June 30, 2008, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At June 30, 2008, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910. The Board of Directors declared a quarterly dividend of $0.41 per share in July 2008. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on the $315 million of AEP Junior Subordinated Debentures issued in March 2008 for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our results of operations, cash flows, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

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

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

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

Cash Flow

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 178	$ 301
Net Cash Flows from Operating Activities	1,197	969
Net Cash Flows Used for Investing Activities	(1,645)	(2,127)
Net Cash Flows from Financing Activities	488	1,029
Net Increase (Decrease) in Cash and Cash Equivalents	40	(129)
Cash and Cash Equivalents at End of Period	$ 218	$ 172

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

	Six Months Ended June 30, 2008	2007
	(in millions)	
Net Income	$ 854	$ 451
Less Discontinued Operations, Net of Tax	(1)	(2)
Income Before Discontinued Operations	853	449
Depreciation and Amortization	736	763
Other	(392)	(243)
Net Cash Flows from Operating Activities	$ 1,197	$ 969

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

Net Cash Flows from Operating Activities were $1.2 billion in 2008 consisting primarily of Income Before Discontinued Operations of $853 million and $736 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 include an increase in under-recovered fuel reflecting higher natural gas prices.

Net Cash Flows from Operating Activities were $1 billion in 2007 consisting primarily of Income Before Discontinued Operations of $449 million and $763 million of noncash depreciation and amortization. Other represents items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items resulted in lower cash from operations due to a number of items, the most significant of which relates primarily to the Texas CTC refund of fuel over-recovery.

Investing Activities

	Six Months Ended June 30, 2008	2007
	(in millions)	
Construction Expenditures	$ (1,608)	$ (1,823)
Acquisition of Darby and Lawrenceburg Plants	-	(427)
Acquisition of Other Assets	(81)	-
Proceeds from Sales of Assets	69	74
Other	(25)	49
Net Cash Flows Used for Investing Activities	$ (1,645)	$ (2,127)

Net Cash Flows Used for Investing Activities were $1.6 billion in 2008 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan. Construction expenditures decreased compared to 2007 due to a decline in environmental, fossil, hydro and nuclear projects partially offset by increased expenditures for new generation and transmission projects.

Net Cash Flows Used for Investing Activities were $2.1 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan. We paid $427 million to purchase gas-fired generating units to acquire capacity at a cost below that of building a new, comparable plant.

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

We forecast approximately $2.2 billion of construction expenditures for the remainder of 2008. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	Six Months Ended June 30, 2008	
	2008	**2007**
	(in millions)	
Issuance of Common Stock	$ 72	$ 90
Issuance/Retirement of Debt, Net	777	1,294
Dividends Paid on Common Stock	(330)	(311)
Other	(31)	(44)
Net Cash Flows from Financing Activities	$ 488	$ 1,029

Net Cash Flows from Financing Activities in 2008 were $488 million primarily due to the issuance of additional debt including $315 million of junior subordinated debentures and a net increase of $1 billion in outstanding senior unsecured notes partially offset by the reacquisition of a net $440 million of pollution control bonds and retirements of $53 million of mortgage notes and $75 million of securitization bonds. See Note 9 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2007 were $1 billion primarily due to issuing $1.1 billion of debt securities including $1 billion of new debt for plant acquisitions and construction and increasing short-term commercial paper borrowings. We paid common stock dividends of $311 million.

Our capital investment plans for 2008 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:

	June 30, 2008	**December 31, 2007**
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 564	$ 507
Rockport Plant Unit 2 Future Minimum Lease Payments	2,142	2,216
Railcars Maximum Potential Loss From Lease Agreement	26	30

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

Summary Obligation Information

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

SIGNIFICANT FACTORS

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

Ohio Electric Security Plan Filings

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

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file MROs. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. Effective January 1, 2009, CSPCo and OPCo will defer the fuel cost under-recoveries and related carrying costs for future recovery over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for unexpected costs and reliability costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. Management expects a PUCO decision on the ESP filings in the fourth quarter of 2008.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $45 million and $36 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $28 million and $19 million, respectively. Such costs would be recovered over an 8 year period beginning January 2011. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future results of operations and cash flows.

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of $2.5 billion and is recovering such costs over a period ending in 2020. TCC has refunded its net other true-up items of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Cash paid for CTC refunds for the six months ended June 30, 2008 and 2007 was $68 million and $170 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 and related orders seeking to further reduce TCC’s true-up recoveries.

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

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but one major respect. It reversed the District Court's decision finding that the PUCT erred by applying an invalid rule to determine the carrying cost rate. The Texas Court of Appeals denied intervenors' motion for rehearing. Management expects intervenors to appeal the decision to the Texas Supreme Court. If upheld on appeal, this ruling could have a favorable effect on TCC's results of operations and cash flows.

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

FERC Market Power Mitigation

FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that FERC should further investigate whether AEP continues to pass FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with FERC's guidelines, and continue to demonstrate lack of market power. Management is unable to predict the outcome of this proceeding; however, if a further investigation by the FERC limits AEP's ability to sell power at market based rates in PJM, it would result in an adverse effect on future off-system sales margins, results of operations and cash flows.

New Generation

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

Operating Company	Project Name		Location	Total Projected Cost (a)	CWIP (b)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
				(in millions)	(in millions)				
PSO	Southwestern	(c)	Oklahoma	$ 56	$ -	Gas	Simple-cycle	150	2008
PSO	Riverside	(d)	Oklahoma	58	-	Gas	Simple-cycle	150	2008
AEGCo	Dresden	(e)	Ohio	309(e)	119	Gas	Combined-cycle	580	2010
SWEPCo	Stall		Louisiana	378	106	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(f)	Arkansas	1,522(f)	407	Coal	Ultra-supercritical	600(f)	2012
APCo	Mountaineer	(g)	West Virginia	2,230(g)	-	Coal	IGCC	629	2012(g)
CSPCo/OPCo	Great Bend	(g)	Ohio	2,700(g)	-	Coal	IGCC	629	2017(g)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC. Turk's CWIP includes joint owners' share.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) The final Riverside Unit was placed in service on June 15, 2008.
(e) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(f) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1,110 million in capital investment. The increase in the cost estimate disclosed in the 2007 Annual Report relates to cost escalations due to the delay in receipt of permits and approvals. See "Turk Plant" section below.
(g) Subject to revision; construction of IGCC plants deferred pending regulatory approval. See "IGCC Plants" section below.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant. In July 2008, the PUCT approved a certificate of convenience and necessity for construction of the plant. We expect a written order in August 2008 which will also provide for the conditions of the PUCT's approval.

SWEPCo is working with the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers for approval later this year. A request to stop pre-construction activities at the site was filed in Federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the Federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

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 the joint owners for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of June 30, 2008, including the joint owners' share, SWEPCo has capitalized approximately $407 million of expenditures and has significant contractual construction commitments for an additional $815 million. As of June 30, 2008, if the plant had been canceled, cancellation fees of $60 million would have been required in order to terminate these construction commitments. If SWEPCo cannot recover its costs, it would have an adverse effect on future results of operations, cash flows and possibly financial condition.

IGCC Plants

We have delayed construction of the West Virginia and Ohio IGCC plants. In May 2008, the Virginia SCC denied APCo's request to reconsider the Virginia SCC previous denial of APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. In July 2008, the IRS awarded $134 million in future tax credits for the IGCC plant. Management continues to pursue the ultimate construction of the IGCC plant. If the West Virginia IGCC plant is canceled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs of $19 million. If the plant is canceled and the deferred costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

In Ohio, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant, but await the result of an Ohio Supreme Court remand to the PUCO regarding recovery of IGCC pre-construction costs. If CSPCo and OPCo were required to refund $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 results of operations and cash flows.

Litigation

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

Environmental Litigation

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

In 2007, the AEP System settled their complaints under a consent decree. CSPCo jointly-owns Beckjord and Stuart Stations with Duke and DP&L. A jury trial in May 2008 returned a verdict of no liability at the jointly-owned Beckjord unit. Settlement discussions are ongoing in the citizen suit action filed by Sierra Club against the jointly-owned units at Stuart Station. 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 results of operations 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 engaged 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 2007 Annual Report.

Clean Air Act Requirements

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

In anticipation of compliance with CAIR in 2009, I&M purchased $8 million of annual CAIR NO_x allowances which are included in inventory as of June 30, 2008. The market value of annual CAIR NO_x allowances decreased in the weeks following this court decision. Management intends to seek recovery of the cost of purchased allowances. If the recovery is denied, it would have an adverse effect on future results of operations and cash flows. None of AEP's other subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to our facilities under the Acid Rain Program and the NO_x SIP Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

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

Global Climate Change

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

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

Clean Water Act Regulations

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

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

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

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157 "Fair Value Measurements" (SFAS 157), enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data. In February 2008, the FASB issued FSP FAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, we recorded an immaterial transition adjustment to beginning retained earnings. The impact of considering our own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption. We partially adopted SFAS 157 effective January 1, 2008. We will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2. See "SFAS 157 "Fair Value Measurements" (SFAS 157)" section of Note 2.

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

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

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

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

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

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

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, natural gas, coal, and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President – AEP Utilities, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

We actively participate in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around risk management contracts. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. We support the work of the CCRO and embrace the disclosure standards applicable to our business activities. The following tables provide information on our risk management activities.

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

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

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

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	MTM of Cash Flow and Fair Value Hedges	Collateral Deposits	Total
Current Assets	$ 653	$ 201	$ 121	$ 975	$ 34	$ (118)	$ 891
Noncurrent Assets	309	144	86	539	14	(64)	489
Total Assets	962	345	207	1,514	48	(182)	1,380
Current Liabilities	(660)	(203)	(124)	(987)	(101)	97	(991)
Noncurrent Liabilities	(202)	(75)	(90)	(367)	(5)	24	(348)
Total Liabilities	(862)	(278)	(214)	(1,354)	(106)	121	(1,339)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 100	$ 67	$ (7)	$ 160	$ (58)	$ (61)	$ 41

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

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2007	$ 156	$ 43	$ (8)	$ 191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(36)	4	-	(32)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2	16	-	18
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	6	3	1	10
Changes in Fair Value Due to Market Fluctuations During the Period (c)	6	1	-	7
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(34)	-	-	(34)
Total MTM Risk Management Contract Net Assets (Liabilities) at June 30, 2008	$ 100	$ 67	$ (7)	160
Net Cash Flow and Fair Value Hedge Contracts				(58)
Collateral Deposits				(61)
Ending Net Risk Management Assets at June 30, 2008				$ 41

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

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 June 30, 2008
(in millions)

	Remainder 2008	2009	2010	2011	2012	After 2012 (f)	Total
Utility Operations:							
Level 1 (a)	$ (6)	$ 1	$ -	$ -	$ -	$ -	$ (5)
Level 2 (b)	8	47	40	16	6	-	117
Level 3 (c)	(29)	(5)	(12)	(8)	(4)	-	(58)
Total	(27)	43	28	8	2	-	54
Generation and Marketing:							
Level 1 (a)	(36)	13	(1)	(1)	-	-	(25)
Level 2 (b)	31	(8)	6	5	5	3	42
Level 3 (c)	(2)	-	8	9	9	26	50
Total	(7)	5	13	13	14	29	67
All Other:							
Level 1 (a)	-	-	-	-	-	-	-
Level 2 (b)	(1)	(4)	(4)	2	-	-	(7)
Level 3 (c)	-	-	-	-	-	-	-
Total	(1)	(4)	(4)	2	-	-	(7)
Total:							
Level 1 (a)	(42)	14	(1)	(1)	-	-	(30)
Level 2 (b)	38	35	42	23	11	3	152
Level 3 (c) (d)	(31)	(5)	(4)	1	5	26	(8)
Total	(35)	44	37	23	16	29	114
Dedesignated Risk Management Contracts (e)	7	14	14	6	5	-	46
Total MTM Risk Management Contract Net Assets (Liabilities)	$ (28)	$ 58	$ 51	$ 29	$ 21	$ 29	$ 160

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

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

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

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

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

(f) There is mark-to-market value of $29 million in individual periods beyond 2012. $13 million of this mark-to-market value is in 2013, $8 million is in 2014, $3 million is in 2015, $3 million is in 2016 and $2 million is in 2017.

The following table reports an estimate of the maximum tenors (contract maturities) of the liquid portion of each energy market.

Maximum Tenor of AEP's Liquid Portion of Risk Management Contracts
As of June 30, 2008

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	30
	Swaps	Gas East, Mid-Continent, Gulf Coast, Texas	30
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	Power East – PJM	36
	Physical Forwards	Power East – Cinergy	54
	Physical Forwards	Power East – PJM West	54
	Physical Forwards	Power East – AEP Dayton (PJM)	54
	Physical Forwards	Power East – ERCOT	42
	Physical Forwards	Power East – Entergy	30
	Physical Forwards	Power West – PV, NP15, SP15, MidC, Mead	42
	Peak Power Volatility (Options)	Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	42
Coal	Physical Forwards	PRB, NYMEX, CSX	42

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

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

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

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

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

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

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2007	$ (1)	$ (25)	$ (26)
Changes in Fair Value	(32)	(4)	(36)
Reclassifications from AOCI for Cash Flow Hedges Settled	1	1	2
Ending Balance in AOCI, June 30, 2008	$ (32)	$ (28)	$ (60)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ (38)	$ (6)	$ (44)

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. We use Moody's Investors Service, Standard & Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating. Based on our analysis, we set appropriate risk parameters for each internally-graded counterparty. We may also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties in order to mitigate credit risk.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At June 30, 2008, our credit exposure net of collateral to sub investment grade counterparties was approximately 20.1%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). The increase from 5.4% at December 31, 2007 is primarily related to an increase in exposure with coal counterparties due to escalating coal prices. Approximately 55% of our credit exposure net of collateral to sub investment grade counterparties is short-term exposure of less than one year. As of June 30, 2008, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
Investment Grade	$ 873	$ 184	$ 689	2	$ 181
Split Rating	36	7	29	4	27
Noninvestment Grade	185	49	136	1	112
No External Ratings:					
Internal Investment Grade	89	-	89	2	63
Internal Noninvestment Grade	68	1	67	2	61
Total as of June 30, 2008	$ 1,251	$ 241	$ 1,010	11	$ 444
Total as of December 31, 2007	$ 673	$ 42	$ 631	6	$ 74

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2010. This table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of June 30, 2008

	Remainder 2008	2009	2010
Estimated Plant Output Hedged	90%	89%	91%

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 June 30, 2008, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

Six Months Ended June 30, 2008 (in millions)				Twelve Months Ended December 31, 2007 (in millions)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$2	$2	$1	$1	$1	$6	$2	$1

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

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

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on our debt portfolio was $32 million.

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

	Three Months Ended 2008	Three Months Ended 2007	Six Months Ended 2008	Six Months Ended 2007
REVENUES				
Utility Operations	$ 3,200	$ 2,818	$ 6,210	$ 5,704
Other	346	328	803	611
TOTAL	3,546	3,146	7,013	6,315
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,053	868	2,033	1,754
Purchased Energy for Resale	366	291	629	537
Other Operation and Maintenance	982	881	1,860	1,819
Gain on Disposition of Assets, Net	(5)	(3)	(8)	(26)
Asset Impairments and Other Related Items	-	-	(255)	-
Depreciation and Amortization	373	372	736	763
Taxes Other Than Income Taxes	191	188	389	374
TOTAL	2,960	2,597	5,384	5,221
OPERATING INCOME	586	549	1,629	1,094
Interest and Investment Income	15	8	31	31
Carrying Costs Income	26	16	43	24
Allowance for Equity Funds Used During Construction	11	6	21	14
INTEREST AND OTHER CHARGES				
Interest Expense	234	213	454	399
Preferred Stock Dividend Requirements of Subsidiaries	-	-	1	1
TOTAL	234	213	455	400
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS (LOSS)	404	366	1,269	763
Income Tax Expense	123	108	416	238
Minority Interest Expense	1	1	2	2
Equity Earnings of Unconsolidated Subsidiaries	-	-	2	5
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	280	257	853	528
DISCONTINUED OPERATIONS, NET OF TAX	1	2	1	2
INCOME BEFORE EXTRAORDINARY LOSS	281	259	854	530
EXTRAORDINARY LOSS, NET OF TAX	-	(79)	-	(79)
NET INCOME	$ 281	$ 180	$ 854	$ 451
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	401,513,958	398,679,242	401,155,975	398,000,712
BASIC EARNINGS PER SHARE				
Income Before Discontinued Operations and Extraordinary Loss	$ 0.70	$ 0.64	$ 2.13	$ 1.33
Discontinued Operations, Net of Tax	-	0.01	-	-
Income Before Extraordinary Loss	0.70	0.65	2.13	1.33
Extraordinary Loss, Net of Tax	-	(0.20)	-	(0.20)
TOTAL BASIC EARNINGS PER SHARE	$ 0.70	$ 0.45	$ 2.13	$ 1.13
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	402,785,942	399,868,900	402,429,019	399,214,277
DILUTED EARNINGS PER SHARE				
Income Before Discontinued Operations and Extraordinary Loss	$ 0.70	$ 0.64	$ 2.12	$ 1.32
Discontinued Operations, Net of Tax	-	0.01	-	0.01
Income Before Extraordinary Loss	0.70	0.65	2.12	1.33
Extraordinary Loss, Net of Tax	-	(0.20)	-	(0.20)
TOTAL DILUTED EARNINGS PER SHARE	$ 0.70	$ 0.45	$ 2.12	$ 1.13
CASH DIVIDENDS PAID PER SHARE	$ 0.41	$ 0.39	$ 0.82	$ 0.78

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 218	$ 178
Other Temporary Investments	243	365
Accounts Receivable:		
Customers	795	730
Accrued Unbilled Revenues	400	379
Miscellaneous	85	60
Allowance for Uncollectible Accounts	(45)	(52)
Total Accounts Receivable	1,235	1,117
Fuel, Materials and Supplies	1,049	967
Risk Management Assets	891	271
Margin Deposits	63	47
Regulatory Asset for Under-Recovered Fuel Costs	202	11
Prepayments and Other	105	70
TOTAL	4,006	3,026
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	20,675	20,233
Transmission	7,651	7,392
Distribution	12,389	12,056
Other (including coal mining and nuclear fuel)	3,479	3,445
Construction Work in Progress	3,257	3,019
Total	47,451	46,145
Accumulated Depreciation and Amortization	16,447	16,275
TOTAL - NET	31,004	29,870
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,234	2,199
Securitized Transition Assets	2,121	2,108
Spent Nuclear Fuel and Decommissioning Trusts	1,362	1,347
Goodwill	76	76
Long-term Risk Management Assets	489	319
Employee Benefits and Pension Assets	481	486
Deferred Charges and Other	923	888
TOTAL	7,686	7,423
TOTAL ASSETS	$ 42,696	$ 40,319

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2008	2007
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,414	$ 1,324
Short-term Debt	705	660
Long-term Debt Due Within One Year	569	792
Risk Management Liabilities	991	240
Customer Deposits	319	301
Accrued Taxes	555	601
Accrued Interest	256	235
Other	817	1,008
TOTAL	5,626	5,161
NONCURRENT LIABILITIES		
Long-term Debt	15,184	14,202
Long-term Risk Management Liabilities	348	188
Deferred Income Taxes	5,021	4,730
Regulatory Liabilities and Deferred Investment Tax Credits	2,895	2,952
Asset Retirement Obligations	1,081	1,075
Employee Benefits and Pension Obligations	677	712
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	134	139
Deferred Credits and Other	1,038	1,020
TOTAL	26,378	25,018
TOTAL LIABILITIES	32,004	30,179
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock – $6.50 Par Value Per Share:		
(21,499,992 shares were held in treasury at June 30, 2008 and December 31, 2007, respectively)	2,754	2,743
Paid-in Capital	4,415	4,352
Retained Earnings	3,651	3,138
Accumulated Other Comprehensive Income (Loss)	(189)	(154)
TOTAL	10,631	10,079
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 42,696	$ 40,319

	2008	2007
Shares Authorized	600,000,000	600,000,000
Shares Issued	423,634,828	421,926,696

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 854	$ 451
Less: Discontinued Operations, Net of Tax	(1)	(2)
Income Before Discontinued Operations	853	449
Adjustments to Reconcile Net Income to Net Cash Flow from Operating Activities:		
Depreciation and Amortization	736	763
Deferred Income Taxes	316	(24)
Deferred Investment Tax Credits	(10)	(13)
Extraordinary Loss, Net of Tax	-	79
Regulatory Provision	-	105
Carrying Costs Income	(43)	(24)
Allowance for Equity Funds Used During Construction	(21)	(14)
Mark-to-Market of Risk Management Contracts	66	22
Amortization of Nuclear Fuel	45	33
Deferred Property Taxes	36	24
Fuel Over/Under-Recovery, Net	(245)	(101)
Gain on Sales of Assets and Equity Investments, Net	(8)	(26)
Change in Other Noncurrent Assets	(195)	(39)
Change in Other Noncurrent Liabilities	(80)	23
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(123)	(81)
Fuel, Materials and Supplies	(82)	(90)
Margin Deposits	(16)	32
Accounts Payable	188	(58)
Customer Deposits	18	24
Accrued Taxes, Net	(61)	49
Accrued Interest	16	67
Other Current Assets	(13)	(21)
Other Current Liabilities	(180)	(210)
Net Cash Flows From Operating Activities	1,197	969
INVESTING ACTIVITIES		
Construction Expenditures	(1,608)	(1,823)
Change in Other Temporary Investments, Net	48	(129)
Purchases of Investment Securities	(635)	(6,827)
Sales of Investment Securities	666	7,035
Acquisition of Nuclear Fuel	(99)	(30)
Acquisition of Darby and Lawrenceburg Plants	-	(427)
Acquisition of Other Assets	(81)	-
Proceeds from Sales of Assets	69	74
Other	(5)	-
Net Cash Flows Used For Investing Activities	(1,645)	(2,127)
FINANCING ACTIVITIES		
Issuance of Common Stock	72	90
Change in Short-term Debt, Net	45	420
Issuance of Long-term Debt	2,204	1,064
Retirement of Long-term Debt	(1,472)	(190)
Dividends Paid on Common Stock	(330)	(311)
Other	(31)	(44)
Net Cash Flows From Financing Activities	488	1,029
Net Increase (Decrease) in Cash and Cash Equivalents	40	(129)
Cash and Cash Equivalents at Beginning of Period	178	301
Cash and Cash Equivalents at End of Period	$ 218	$ 172
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 412	$ 304
Net Cash Paid for Income Taxes	131	128
Noncash Acquisitions Under Capital Leases	35	23
Noncash Acquisition of Land/Mineral Rights	42	-
Construction Expenditures Included in Accounts Payable at June 30,	328	295
Acquisition of Nuclear Fuel in Accounts Payable at June 30,	-	31
Noncash Assumption of Liabilities Related to Acquisitions	-	5

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	Common Stock					
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 9,412
FIN 48 Adoption, Net of Tax				(17)		(17)
Issuance of Common Stock	3	16	74			90
Common Stock Dividends				(311)		(311)
Other			10			10
TOTAL						9,184
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $8					15	15
Securities Available for Sale, Net of Tax of $3					(5)	(5)
SFAS 158 Costs Established as a Regulatory Asset for the Reapplication of SFAS 71, Net of Tax of $6					11	11
NET INCOME				451		451
TOTAL COMPREHENSIVE INCOME						472
JUNE 30, 2007	421	$ 2,734	$ 4,305	$ 2,819	$ (202)	$ 9,656
DECEMBER 31, 2007	422	$ 2,743	$ 4,352	$ 3,138	$ (154)	$ 10,079
EITF 06-10 Adoption, Net of Tax of $6				(10)		(10)
SFAS 157 Adoption, Net of Tax of $0				(1)		(1)
Issuance of Common Stock	2	11	61			72
Common Stock Dividends				(330)		(330)
Other			2			2
TOTAL						9,812
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Cash Flow Hedges, Net of Tax of $19					(34)	(34)
Securities Available for Sale, Net of Tax of $4					(7)	(7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3					6	6
NET INCOME				854		854
TOTAL COMPREHENSIVE INCOME						819
JUNE 30, 2008	424	$ 2,754	$ 4,415	$ 3,651	$ (189)	$ 10,631

See Condensed Notes to Condensed Consolidated Financial Statements.

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

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

Earnings Per Share

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

	Three Months Ended June 30,			
	2008		2007	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to Common Stock	$ 281		$ 180	
Average Number of Basic Shares Outstanding	401.5	$ 0.70	398.7	$ 0.45
Average Dilutive Effect of:				
Performance Share Units	0.9	-	0.6	-
Stock Options	0.2	-	0.4	-
Restricted Stock Units	0.1	-	0.1	-
Restricted Shares	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	402.8	$ 0.70	399.9	$ 0.45

	Six Months Ended June 30,			
	2008		2007	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to Common Stock	$ 854		$ 451	
Average Number of Basic Shares Outstanding	401.2	$ 2.13	398.0	$ 1.13
Average Dilutive Effect of:				
Performance Share Units	0.8	(0.01)	0.6	-
Stock Options	0.2	-	0.4	-
Restricted Stock Units	0.1	-	0.1	-
Restricted Shares	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	402.4	$ 2.12	399.2	$ 1.13

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

Options to purchase 146,900 and 83,450 shares of common stock were outstanding at June 30, 2008 and 2007, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the quarter-end market price of the common shares and, therefore, the effect would be antidilutive.

Supplementary Information

Related Party Transactions	Three Months Ended June 30, 2008	2007	Six Months Ended June 30, 2008	2007
	(in millions)		(in millions)	
AEP Consolidated Revenues – Utility Operations:				
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% owned)	$ (13)	$ (4)	$ (25)	$ (4)
AEP Consolidated Revenues – Other:				
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	5	8	14	17
AEP Consolidated Expenses – Purchased Energy for Resale:				
Ohio Valley Electric Corporation (43.47% Owned)	61	56	124	105
Sweeny Cogeneration Limited Partnership (a)	-	29	-	59

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

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

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

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

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

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

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

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

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

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

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

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 167	$ -	$ -	$ 51	$ 218
Other Temporary Investments:					
Cash and Cash Equivalents (b)	$ 188	$ -	$ -	$ 39	$ 227
Equity Securities	16	-	-	-	16
Total Other Temporary Investments	$ 204	$ -	$ -	$ 39	$ 243
Risk Management Assets:					
Risk Management Contracts (c)	$ 375	$ 5,660	$ 143	$ (4,892)	$ 1,286
Cash Flow and Fair Value Hedges (c)	-	65	-	(17)	48
Dedesignated Risk Management Contracts (d)	-	-	-	46	46
Total Risk Management Assets	$ 375	$ 5,725	$ 143	$ (4,863)	$ 1,380
Spent Nuclear Fuel and Decommissioning Trusts:					
Cash and Cash Equivalents (e)	$ -	$ 17	$ -	$ 12	$ 29
Debt Securities	326	508	-	-	834
Equity Securities	499	-	-	-	499
Total Spent Nuclear Fuel and Decommissioning Trusts	$ 825	$ 525	$ -	$ 12	$ 1,362
Total Assets	$ 1,571	$ 6,250	$ 143	$ (4,761)	$ 3,203
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (c)	$ 405	$ 5,508	$ 151	$ (4,831)	$ 1,233
Cash Flow and Fair Value Hedges (c)	8	115	-	(17)	106
Total Risk Management Liabilities	$ 413	$ 5,623	$ 151	$ (4,848)	$ 1,339

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

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

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

(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 Utility Operations Revenues over the remaining life of the contract.

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

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 June 30, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of April 1, 2008	$ 49	$ 22	$ 17
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	(2)	-	-
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(1)	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements	-	(22)	(17)
Transfers in and/or out of Level 3 (b)	(8)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(46)	-	-
Balance as of June 30, 2008	$ (8)	$ -	$ -

Six Months Ended June 30, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of January 1, 2008	$ 49	$ -	$ -
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	(2)	-	-
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(3)	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements	-	(118)	(17)
Transfers in and/or out of Level 3 (b)	(1)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(51)	-	-
Balance as of June 30, 2008	$ (8)	$ -	$ -

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

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

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

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

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

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

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

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

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Although we have not completed our analysis, we expect that the adoption of this standard will have an immaterial impact on our financial statements. We will adopt SFAS 160 effective January 1, 2009.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2008 balance sheet, we netted $182 million of cash collateral received from third parties against short-term and long-term risk management assets and $121 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, earnings per share calculations, leases, hedge accounting, 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 results of operations and financial position.

EXTRAORDINARY ITEM

In April 2007, Virginia passed legislation to reestablish regulation for retail generation and supply of electricity. As a result, we recorded an extraordinary loss of $118 million ($79 million, net of tax) during the second quarter of 2007 for the reestablishment of regulatory assets and liabilities related to our Virginia retail generation and supply operations. In 2000, we discontinued SFAS 71 regulatory accounting in our Virginia jurisdiction for retail generation and supply operations due to the passage of legislation for customer choice and deregulation.

3. RATE MATTERS

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

Ohio Rate Matters

Ohio Electric Security Plan Filings

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

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file MROs. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. Effective January 1, 2009, CSPCo and OPCo will defer the fuel cost under-recoveries and related carrying costs for future recovery over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for unexpected costs and reliability costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. Management expects a PUCO decision on the ESP filings in the fourth quarter of 2008.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $45 million and $36 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $28 million and $19 million, respectively. Such costs would be recovered over an 8 year period beginning January 2011. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future results of operations and cash flows.

2008 Generation Rider and Transmission Rider Rate Settlement

On January 30, 2008, the PUCO approved a settlement agreement, among CSPCo, OPCo and other parties, under the additional average 4% generation rate increase and transmission cost recovery rider ("TCRR") provisions of the RSP. The increase was to recover additional governmentally-mandated costs including incremental environmental costs. Under the settlement, the PUCO also approved recovery through the TCRR of increased PJM costs associated with transmission line losses of $39 million each for CSPCo and OPCo. As a result, CSPCo and OPCo established regulatory assets in the first quarter of 2008 of $12 million and $14 million, respectively, related to the future recovery of increased PJM billings from June 2007 to December 2007. The PUCO also approved a credit applied to the TCRR of $10 million for OPCo and $8 million for CSPCo for a reduction in PJM net congestion costs. To the extent that collections for the TCRR items are over/under actual net costs, CSPCo and OPCo will defer the difference and adjust future customer billings to reflect actual costs including carrying costs on the unrecovered deferral. Under the terms of the settlement, although the increased PJM costs associated with transmission line losses will be recovered through the TCRR, these recoveries will still be applied to reduce the annual average 4% generation rate increase limitation. In addition, the PUCO approved recoveries through generation rates of environmental costs and related carrying costs of $29 million for CSPCo and $5 million for OPCo. These RSP rate adjustments were implemented in February 2008.

In February 2008, Ormet, a major industrial customer, filed a motion to intervene and an application for rehearing of the PUCO's January 2008 RSP order claiming the settlement inappropriately shifted $4 million in cost recovery to Ormet. In March 2008, the PUCO granted Ormet's motion to intervene. Ormet's rehearing application also was granted for the purpose of providing the PUCO with additional time to consider the issues raised by Ormet. Management cannot predict the outcome of this rehearing process.

Ohio IGCC Plant

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

In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period CSPCo and OPCo each collected $12 million in pre-construction costs.

The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 costs associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 pending further hearings.

In August 2006, intervenors filed four separate appeals of the PUCO's order in the IGCC proceeding. In March 2008, the Ohio Supreme Court issued its opinion affirming in part, and reversing in part the PUCO's order and remanded the matter back to the PUCO. The Ohio Supreme Court held that while there could be an opportunity under existing law to recover a portion of the IGCC costs in distribution rates, traditional rate making procedures would apply to the recoverable portion. The Ohio Supreme Court did not address the matter of refunding the Phase 1 cost recovery and declined to create an exception to its precedent of denying claims for refund of past recoveries from approved orders of the PUCO.

Recent estimates of the cost to build the proposed IGCC plant are approximately $2.7 billion. Management continues to pursue the ultimate construction of the IGCC plant. However, in light of the Ohio Supreme Court's decision, CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of 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 results of operations and cash flows.

Ormet

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

CSPCo and OPCo each amortized $5 million of this regulatory liability to income for the six months ended June 30, 2008 based on the previously approved 2007 price of $47.69 per MWH. In December 2007, CSPCo and OPCo submitted for approval a market price of $53.03 per MWH for 2008. The PUCO has not yet approved the increase. If the PUCO approves a market price for 2008 below $47.69, it could have an adverse effect on future results of operations and cash flows. A price above $47.69 should result in a favorable effect. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo more profitable market priced off-system sales.

Texas Rate Matters

TEXAS RESTRUCTURING

TCC Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of $2.5 billion and is recovering such costs over a period ending in 2020. TCC has refunded its net other true-up items of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Cash paid for CTC refunds for the six months ended June 30, 2008 and 2007 was $68 million and $170 million, respectively. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. The significant items appealed by TCC are:

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

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

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

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but one major respect. It reversed the District Court's decision finding that the PUCT erred by applying an invalid rule to determine the carrying cost rate. The Texas Court of Appeals denied intervenors' motion for rehearing. Management expects intervenors to appeal the decision to the Texas Supreme Court. If upheld on appeal, this ruling could have a favorable effect on TCC's results of operations and cash flows.

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

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

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

The IRS issued final regulations on March 20, 2008 addressing Accumulated Deferred Investment Tax Credit (ADITC) and Excess Deferred Federal Income Tax (EDFIT) normalization requirements. Consistent with the Private Letter Ruling TCC received in 2006, the regulations clearly state that TCC will sustain a normalization violation if the PUCT orders TCC to flow the tax benefits to customers. TCC notified the PUCT that the final regulations were issued. TCC expects that the PUCT will allow TCC to retain and not refund these amounts, which will have a favorable effect on future results of operations and cash flows as TCC will record the ADITC and EDFIT tax benefits in income due to the sale of the generating plants that generated the tax benefits.

However, if the PUCT orders TCC to flow the tax benefits to customers, thereby causing TCC to have a normalization violation, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $103 million as of June 30, 2008, and a loss of TCC's right to claim accelerated tax depreciation in future tax returns. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are actually returned to ratepayers under a nonappealable order. Management intends to continue its efforts to work with the PUCT to resolve the issue and avoid a normalization violation.

TCC and TNC Deferred Fuel

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

The PUCT or another interested party could file a complaint at the FERC to challenge the allocation of off-system sales margins under FERC-approved allocation agreements. In December 2007, some cities served by TNC requested the PUCT to initiate, or order TNC to initiate a proceeding at the FERC to determine if AEP misapplied the allocation methodology under the FERC-approved agreements. In January 2008, TNC filed a response with the PUCT recommending the cities' request be denied. Although management cannot predict if a complaint will be filed at the FERC, management believes its allocations were in accordance with the then-existing FERC-approved allocation agreements and additional off-system sales margins should not be retroactively reallocated to the AEP West companies including TCC and TNC.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made in lieu of reducing stranded cost recoveries in the True-up Proceeding. As a result, TCC's stranded cost recovery, which is currently on appeal, may be affected by a PUCT remedy.

In December 2007, the Texas Court of Appeals issued a decision in CenterPoint's, a nonaffiliated Texas utility, true-up proceeding determining that even though excess earnings had been previously refunded to the affiliated REP, CenterPoint still must reduce stranded cost recoveries in its true-up proceeding. In 2005, TCC reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset of $55 million representing a receivable from the REPs for prior refunds to them by TCC. However, certain parties have taken positions that, if adopted, could result in TCC being required to refund additional amounts of excess earnings or interest through the true-up process without receiving a refund back from the REPs. If this were to occur it would have an adverse effect on future results of operations 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 these matters and whether they will adversely affect future results of operations, cash flows and financial condition.

OTHER TEXAS RATE MATTERS

Stall Unit

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

Turk Plant

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

Virginia Rate Matters

Virginia Base Rate Filing

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

Virginia E&R Costs Recovery Filing

As of June 30, 2008, APCo has $97 million of deferred Virginia incremental E&R costs. Currently APCo is recovering $16 million of the deferral for incremental costs incurred through September 30, 2006. In May 2008, APCo filed for recovery of deferred incremental E&R costs incurred from October 1, 2006 through December 31, 2007 which totals $50 million. The remaining deferral will be requested in a 2009 filing. As of June 30, 2008, APCo has $22 million of unrecorded E&R equity carrying costs of which $7 million should increase 2008 annual earnings as collected. In connection with the 2009 filing, the Virginia SCC will determine the level of incremental E&R costs being collected in base revenues since October 2006 that APCo has estimated to be $48 million annually. If the Virginia SCC were to determine that these recovered base revenues are in excess of $48 million a year, it would require that the E&R deferrals be reduced by the excess amount, thus adversely affecting future earnings and cash flows.

In July 2008, the Old Dominion Committee for Fair Utility Rates (ODC) filed a motion to dismiss the E&R filing based on ODC's belief that the opportunity to collect E&R surcharges expires December 31, 2008. A dismissal would not eliminate APCo's ability to request for future recovery of its deferred E&R costs. APCo filed a response requesting the Virginia SCC to deny ODC's motion. If the Virginia SCC were to disallow any additional portion of APCo's deferral, it would also have an adverse effect on future results of operations and cash flows. If the outstanding request for E&R recovery is approved it will have a favorable effect on future cash flows.

Virginia Fuel Clause Filings

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

In February 2008, the Virginia SCC issued an order that approved a reduced fuel factor effective with the February 2008 billing cycle. The order terminated the off-system sales margin rider and approved a 75%-25% sharing of off-system sales margins between customers and APCo effective September 1, 2007 as required by the re-regulation legislation in Virginia. The order also allows APCo to include in its monthly under/over recovery deferrals the Virginia jurisdictional share of PJM transmission line loss costs from June 2007 to June 2008 which totaled $28 million. The adjusted factor increases annual revenues by $4 million. The order authorized the Virginia SCC staff and other parties to make specific recommendations to the Virginia SCC in APCo's next fuel factor proceeding to ensure accurate assignment of the prudently incurred PJM transmission line loss costs to APCo's Virginia jurisdictional operations. Management believes the incurred PJM transmission line loss costs are prudently incurred and are being properly assigned to APCo's Virginia jurisdictional operations.

In February 2008, the Old Dominion Committee for Fair Utility Rates (ODC) filed a notice of appeal to the Supreme Court of Virginia appealing the Virginia SCC's decisions regarding off-system sales margins and PJM transmission line loss costs. In May 2008, the ODC withdrew its appeal.

In July 2008, APCo filed its next fuel factor proceeding with the Virginia SCC and requested an annualized increase of $132 million effective September 1, 2008. The increase primarily relates to increases in coal costs.

If costs included in APCo's Virginia fuel under/over recovery deferrals are disallowed, it could result in an adverse effect on future results of operations and cash flows.

APCo's Virginia SCC Filing for an IGCC Plant

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

The Virginia SCC issued an order in April 2008 denying APCo's requests stating the belief that the estimated cost may be significantly understated. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In April 2008, APCo filed a petition for reconsideration in Virginia. In May 2008, the Virginia SCC denied APCo's request to reconsider its previous ruling. In July 2008, the IRS awarded $134 million in future tax credits for the IGCC plant. Management continues to pursue the ultimate construction of the IGCC plant; however, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is canceled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is canceled and the deferred costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

<u>West Virginia Rate Matters</u>

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

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

The ENEC is subject to a true up to actual costs and should have no earnings effect due to the deferral of any over/under-recovery of actual ENEC costs. The construction cost and reliability surcharges are not subject to a true up to actual costs and could result in an adverse under recovery.

APCo's West Virginia IGCC Plant Filing

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

In June 2007, APCo filed testimony with the WVPSC supporting the requests for a CCN and for pre-approval of a surcharge rate mechanism to provide for the timely recovery of both pre-construction costs and the ongoing finance costs of the project during the construction period as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. In March 2008, the WVPSC granted APCo the CCN to build the plant and the request for cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order. At the time of the filing, the cost of the plant was estimated at $2.2 billion. In July 2008, based on the order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed (See the "APCo's Virginia SCC Filing for an IGCC Plant" section above). Through June 30, 2008, APCo deferred for future recovery pre-construction IGCC costs of $8 million applicable to the West Virginia jurisdiction and $2 million applicable to the FERC jurisdiction. In July 2008, the IRS awarded $134 million in future tax credits for the IGCC plant. Management continues to pursue the ultimate construction of the IGCC plant; however, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is canceled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is canceled and the deferred costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

<u>Indiana Rate Matters</u>

Indiana Rate Filing

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase includes the $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. The depreciation reduction will no longer favorably impact earnings if and when tariff rates are revised to reflect the reduction. The filing requests trackers for certain variable components of the cost of service including recently increased PJM costs associated with transmission line losses due to the implementation of marginal loss pricing and other RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and environmental compliance costs. The trackers would initially increase annual revenues by an additional $45 million. I&M proposes to share with ratepayers, through a tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million. A decision is expected from the IURC by June 2009.

<u>Kentucky Rate Matters</u>

Validity of Nonstatutory Surcharges

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

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

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of marginal loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM beginning May 2008. Therefore, in the second quarter of 2008, KPCo recorded $13 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through June 2008 of which $7 million related to 2007.

<u>Oklahoma Rate Matters</u>

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

In 2004, intervenors and the OCC staff argued that AEP had inappropriately under allocated off-system sales credits to PSO by $37 million for the period June 2000 to December 2004 under a FERC-approved allocation agreement. An ALJ assigned to hear intervenor claims found that the OCC lacked authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In October 2007, the OCC adopted the ALJ's recommendation and orally directed the OCC staff to explore filing a complaint at FERC alleging the allocation of off-system sales margins to PSO is not in compliance with the FERC-approved methodology which could result in an adverse effect on future results of operations and cash flows for AEP Consolidated and the AEP East companies. In June 2008, the ALJ issued a final recommendation and incorporated the prior finding that the OCC lacked authority to review AEP's application of a FERC-approved methodology. The OCC is scheduled to consider the final recommendation in August 2008. To date, no claim has been asserted at the FERC and management continues to believe that the allocation is consistent with the FERC-approved agreement.

In February 2006, the OCC enacted a rule, requiring the OCC staff to conduct prudence reviews on PSO's generation and fuel procurement processes, practices and costs on a periodic basis. PSO filed testimony in June 2007 covering a prudence review for the year 2005. The OCC staff and intervenors filed testimony in September 2007, and hearings were held in November 2007. The only major issue in the proceeding was the alleged under allocation of off-system sales credits under the FERC-approved allocation methodology, which was determined not to be jurisdictional to the OCC. Consistent with her prior recommendation, the ALJ found that the OCC lacked authority to alter the FERC-approved methodology and that PSO's fuel costs were prudent. The OCC is scheduled to consider the ALJ's findings and rule in August 2008.

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

Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings and prudence reviews or whether a complaint will be filed at FERC regarding the off-system sales allocation issue. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and that it allocated off-system sales credits consistent with governing FERC-approved agreements. If a complaint is filed at FERC resulting in an unfavorable decision, it could have an adverse effect on results of operations and cash flows.

Red Rock Generating Facility

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

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

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

Oklahoma 2007 Ice Storms

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

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

In June 2008, PSO adjusted its regulatory asset to true-up the estimated costs to reflect actual costs as of June 30, 2008. After the true-up, application of proceeds from to-date sales of excess SO_2 emission allowances and carrying costs, the ice storm regulatory asset as of June 30, 2008 was $64 million. In July 2008, PSO filed with the OCC to establish the recovery rider and the final recoverable December 2007 ice storm costs. The estimate of future gains from the sale of SO_2 emission allowances has significantly declined with the decrease in value of such allowances. As a result, estimated collections from customers through the special storm damage recovery rider will be higher than the estimate in the settlement agreement. Nonetheless, management believes that the settlement provides for full recovery of the remaining deferral.

2008 Oklahoma Annual Fuel Factor Filing

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

2008 Oklahoma Base Rate Filing

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million on an annual basis. PSO recovers costs related to new peaking units recently placed into service through the Generation Cost Recovery Rider (GCRR). Upon implementation of the new base rates, PSO will recover these costs through the new base rates and the GCRR will terminate. Therefore, PSO's net annual requested increase in total revenues is $117 million. The requested increase is based upon a test year ended February 29, 2008, adjusted for known and measurable changes through August 2008, which is consistent with the ratemaking treatment adopted by the OCC in PSO's 2006 base rate case. The proposed revenue requirement reflects a return on equity of 11.25%. PSO expects hearings to begin in December 2008 and new rates effective in the first quarter of 2009.

Louisiana Rate Matters

Louisiana Compliance Filing

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

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

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

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

In April 2008, SWEPCo filed the first FRP which would increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%. In June 2008, SWEPCo recorded a $3 million regulatory liability related to the reduction in generation depreciation rates.

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 estimated to cost $378 million, excluding AFUDC, and is expected to be in-service in mid-2010.

In March 2007, the PUCT approved SWEPCo's request for a certificate for the facility based on a prior cost estimate. In February 2008, the LPSC staff submitted testimony in support of the Stall Unit and one intervenor submitted testimony opposing the Stall Unit due to the increase in cost. The LPSC held hearings in April 2008. In July 2008, an ALJ in the LPSC proceeding recommended approval of the Stall Unit. The APSC has not established a procedural schedule at this time. The Louisiana Department of Environmental Quality issued an air permit for the unit in March 2008. If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized pre-construction costs including any cancellation fees. As of June 30, 2008, SWEPCo has capitalized pre-construction costs of $106 million and has contractual construction commitments of an additional $191 million. As of June 30, 2008, if the plant had been canceled, cancellation fees of $60 million would have been required in order to terminate these construction commitments. If SWEPCo canceled the plant and cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future results of operations and cash flows.

Turk Plant

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

<u>Arkansas Rate Matters</u>

Turk Plant

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

In November 2007, the APSC granted approval to build the plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant. In July 2008, the PUCT approved a certificate of convenience and necessity for construction of the plant. We expect a written order in August 2008 which will also provide for the conditions of the PUCT's approval.

SWEPCo is working with the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers for approval later this year. A request to stop pre-construction activities at the site was filed in Federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the Federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of June 30, 2008, including the joint owners' share, SWEPCo has capitalized approximately $407 million of expenditures and has significant contractual construction commitments for an additional $815 million. As of June 30, 2008, if the plant had been canceled, cancellation fees of $60 million would have been required in order to terminate these construction commitments. If SWEPCo cannot recover its costs, it would have an adverse effect on future results of operations, cash flows and possibly financial condition.

Stall Unit

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

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC’s direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues.

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

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ’s initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the ALJ’s initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ’s findings on key issues are largely without merit. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ’s initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

During 2006, the AEP East companies provided reserves of $37 million for net refunds for current and future SECA settlements. After reviewing existing settlements, the AEP East companies increased their reserves by an additional $5 million in December 2007.

Completed and in-process settlements cover $107 million of the $220 million of SECA revenues and will consume about $7 million of the reserve for refund, leaving approximately $113 million of contested SECA revenues and $35 million of refund reserves.

If the FERC adopts the ALJ’s decision and/or AEP cannot settle the remaining unsettled claims within the amount reserved for refunds, it will have an adverse effect on future results of operations and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $35 million is adequate to cover all remaining settlements. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if such are necessary.

The FERC PJM Regional Transmission Rate Proceeding

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

The AEP East companies filed for and in 2006 obtained increases in its wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 85% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future results of operations and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 15% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

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

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in additional annual revenues of approximately $9 million from nonaffiliated customers within PJM. AEP requested an effective date of October 1, 2008. Retail rates are not immediately affected by the filing at the FERC, but retail rates in Ohio would reflect the revised FERC transmission rate through the Transmission Cost Recovery Rider (TCRR) effective January 2009 resulting in additional annual revenues of approximately $22 million. Management is unable to predict the outcome of this filing.

FERC Market Power Mitigation

FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that FERC should further investigate whether AEP continues to pass FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with FERC's guidelines, and continue to demonstrate lack of market power. Management is unable to predict the outcome of this proceeding; however, if a further investigation by the FERC limits AEP's ability to sell power at market based rates in PJM, it would result in an adverse effect on future off-system sales margins, results of operations and cash flows.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2007 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters Of Credit

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. As the Parent, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At June 30, 2008, the maximum future payments for LOCs issued under the two $1.5 billion credit facilities are approximately $58 million with maturities ranging from August 2008 to October 2009.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. As of June 30, 2008, $371 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate demand notes.

Guarantees Of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of June 30, 2008, SWEPCo has collected approximately $36 million through a rider for final mine closure costs, of which approximately $7 million is recorded in Other Current Liabilities, $8 million is recorded in Asset Retirement Obligations and $21 million is recorded in Deferred Credits and Other on our Condensed Consolidated Balance Sheets.

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

Indemnifications And Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sales agreements is discussed in the 2007 Annual Report, "Dispositions" section of Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.3 billion (approximately $1 billion relates to the Bank of America (BOA) litigation, see "Enron Bankruptcy" section of this note). There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Master Operating Lease

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

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. We intend to maintain the lease for twenty years, via renewal options. Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 84% to 77% of the projected fair market value of the equipment.

In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as new operating leases for I&M and SWEPCo. The future minimum lease obligation is $21 million for I&M and $24 million for SWEPCo as of June 30, 2008. I&M and SWEPCo intend to renew these leases for the full remaining terms and have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee discussed above is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $14 million ($9 million, net of tax).

We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. The alleged modifications occurred over a 20-year period. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units.

The AEP System settled their cases in 2007. A case is still pending that could affect CSPCo's share of jointly-owned units at the Stuart Station. The Stuart units, operated by DP&L, are equipped with SCR and flue gas desulfurization equipment (FGD or scrubbers) controls. A trial on liability issues was scheduled for August 2008.

The Court issued a stay to allow the parties to pursue settlement discussions. Those discussions are ongoing. Another case involving a jointly-owned Beckjord unit had a liability trial in May 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit.

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 our jointly-owned units. 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 market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect our future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs' attorneys' fees and costs. The consent decree was entered as a final order in June 2008.

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

In February 2008, the Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that the permit alteration issued by TCEQ was improper. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit.

We are unable to predict the timing of any future action by the Federal EPA or the effect of such action on our results of operations, cash flows or financial condition.

Carbon Dioxide (CO_2) Public Nuisance Claims

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

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. We believe the action is without merit and intend to defend against the claims.

Clean Air Act Interstate Rule

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

In anticipation of compliance with CAIR in 2009, I&M purchased $8 million of annual CAIR NO_x allowances which are included in inventory as of June 30, 2008. The market value of annual CAIR NO_x allowances decreased in the weeks following this court decision. Management intends to seek recovery of the cost of purchased allowances. If the recovery is denied, it would have an adverse effect on future results of operations and cash flows. None of AEP's other subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to our facilities under the Acid Rain Program and the NO_x SIP Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

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

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms and recorded approximately $1 million of expense. As the remediation work is completed, I&M's cost may increase. I&M cannot predict the amount of additional cost, if any. At present, our estimates do not anticipate material cleanup costs for this site.

TEM Litigation

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

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

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

Enron Bankruptcy

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

In February 2004, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We objected to Enron's attempted rejection of these agreements and filed an adversary proceeding contesting Enron's right to reject these agreements.

In 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led the lending syndicate involving the monetization of the cushion gas to Enron and its subsidiaries. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false. In April 2005, the Judge entered an order severing and transferring the declaratory judgment claims involving the right to use and cushion gas consent agreements to the Southern District of New York and retaining the four counts alleging breach of contract, fraud and negligent misrepresentation in the Southern District of Texas. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. Trial in federal court in Texas was continued pending a decision on the motions for summary judgment in the New York case.

In August 2007, the judge in the New York action issued a decision granting BOA summary judgment and dismissing our claims. In December 2007, the judge held that BOA is entitled to recover damages of approximately $347 million ($437 million and $427 million including interest at June 30, 2008 and December 31, 2007, respectively) less a to be determined amount BOA would have incurred to remove 55 BCF of natural gas from the Bammel storage facility. The judge denied our Motion for Reconsideration. We plan to appeal the court's decision once the court enters a final judgment. If the Court enters a final judgment adverse to us and we appeal from the judgment, we will be required under court rules to post security in the form of a bond or stand-by letter of credit covering the amount of the judgment entered against us.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The amounts discussed above are included in Deferred Credits and Other on our Condensed Consolidated Balance Sheets.

Shareholder Lawsuits

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

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In June 2008, we settled all of the cases pending against us in California state court along with all of the cases brought against us in federal court by plaintiffs in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the remaining provision balance is adequate.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that we sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

5. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

2008

Erlbacher companies (MEMCO Operations segment)

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

2007

Darby Electric Generating Station (Utility Operations segment)

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

Lawrenceburg Generating Station (Utility Operations segment)

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for $325 million and the assumption of liabilities of $3 million. AEGCo completed the purchase in May 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW. AEGCo sells the power to CSPCo through a FERC-approved unit power agreement.

DISPOSITIONS

2008

None

2007

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville for $43 million plus working capital adjustments. The sale did not have an impact on our results of operations nor do we expect any remaining litigation to have a significant effect on our results of operations.

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

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

Texas REPs (Utility Operations segment)

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

DISCONTINUED OPERATIONS

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

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

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

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

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

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

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

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 23	$ 11	$ 11
Interest Cost	62	57	28	26
Expected Return on Plan Assets	(84)	(82)	(28)	(26)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	10	14	2	3
Net Periodic Benefit Cost	$ 13	$ 12	$ 20	$ 21

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 50	$ 47	$ 21	$ 21
Interest Cost	125	116	56	52
Expected Return on Plan Assets	(168)	(167)	(56)	(52)
Amortization of Transition Obligation	-	-	14	14
Amortization of Net Actuarial Loss	19	29	5	6
Net Periodic Benefit Cost	$ 26	$ 25	$ 40	$ 41

7. BUSINESS SEGMENTS

As outlined in our 2007 Annual Report, our primary business strategy and the core of our business are to focus on our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio continues to have commission-determined rates transitioning from cost-based to market-based rates. The legislature in Ohio is currently considering possibly returning to some form of cost-based rate-regulation or a hybrid form of rate-regulation for generation. While our Utility Operations segment remains our primary business segment, other segments include our MEMCO Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Utility Operations

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

MEMCO Operations

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

Generation and Marketing

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

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

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

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

	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended June 30, 2008						
Revenues from:						
External Customers	$ 3,200(d)	$ 144	$ 137	$ 65	$ -	$ 3,546
Other Operating Segments	113(d)	7	(26)	(57)	(37)	-
Total Revenues	$ 3,313	$ 151	$ 111	$ 8	$ (37)	$ 3,546
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 263	$ 3	$ 26	$ (12)	$ -	$ 280
Discontinued Operations, Net of Tax	-	-	-	1	-	1
Net Income (Loss)	$ 263	$ 3	$ 26	$ (11)	$ -	$ 281

	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended June 30, 2007						
Revenues from:						
External Customers	$ 2,818(d)	$ 116	$ 218	$ (6)	$ -	$ 3,146
Other Operating Segments	136(d)	3	(113)	12	(38)	-
Total Revenues	$ 2,954	$ 119	$ 105	$ 6	$ (38)	$ 3,146
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 238	$ 7	$ 15	$ (3)	$ -	$ 257
Discontinued Operations, Net of Tax	-	-	-	2	-	2
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income (Loss)	$ 159	$ 7	$ 15	$ (1)	$ -	$ 180

	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Six Months Ended June 30, 2008						
Revenues from:						
External Customers	$ 6,210(d)	$ 282	$ 408	$ 113	$ -	$ 7,013
Other Operating Segments	397(d)	11	(238)	(100)	(70)	-
Total Revenues	$ 6,607	$ 293	$ 170	$ 13	$ (70)	$ 7,013
Income Before Discontinued Operations and Extraordinary Loss	$ 673	$ 10	$ 27	$ 143	$ -	$ 853
Discontinued Operations, Net of Tax	-	-	-	1	-	1
Net Income	$ 673	$ 10	$ 27	$ 144	$ -	$ 854

Six Months Ended June 30, 2007	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 5,704(d)	$ 233	$ 333	$ 45	$ -	$ 6,315
Other Operating Segments	283(d)	6	(186)	(33)	(70)	-
Total Revenues	$ 5,987	$ 239	$ 147	$ 12	$ (70)	$ 6,315
Income Before Discontinued Operations and Extraordinary Loss	$ 491	$ 22	$ 14	$ 1	$ -	$ 528
Discontinued Operations, Net of Tax	-	-	-	2	-	2
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income	$ 412	$ 22	$ 14	$ 3	$ -	$ 451

June 30, 2008	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (c)	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 46,776	$ 302	$ 576	$ 42	$ (245)	$ 47,451
Accumulated Depreciation and Amortization	16,266	66	126	7	(18)	16,447
Total Property, Plant and Equipment – Net	$ 30,510	$ 236	$ 450	$ 35	$ (227)	$ 31,004
Total Assets	$ 41,519	$ 374	$ 953	$ 13,182	$ (13,332)(b)	$ 42,696

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

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually liquidate and completely expire in 2011.
- The first quarter 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The cash settlement of $255 million ($163 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

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

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

(d) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases for these energy marketing contracts as a reduction of Revenues from External Customers for the Utility Operations segment. This is offset by the Utility Operations segment's related sales to AEPEP in Revenues from Other Operating Segments of $26 million and $113 million for the three months ended June 30, 2008 and 2007, respectively, and $238 million and $186 million for the six months ended June 30, 2008 and 2007, respectively. The Generation and Marketing segment reports purchases related to these contracts as a reduction to Revenues from Other Operating segments.

8. INCOME TAXES

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

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

We are no longer subject to U.S. federal examination for years before 2000. However, we have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. We have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

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

Federal Tax Legislation

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of a new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. We announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. We filed applications for the West Virginia and Ohio IGCC projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during the first round of credit awards. After one of the original credit recipients surrendered their credits in the Fall of 2007, the IRS announced a supplemental credit round for the Spring of 2008. We filed a new application in 2008 for the West Virginia IGCC project and in July 2008 the IRS awarded the project $134 million in credits subject to entering into a memorandum of understanding with the IRS.

State Tax Legislation

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

9. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	June 30, 2008	December 31, 2007
	(in millions)	
Senior Unsecured Notes	$ 10,940	$ 9,905
Pollution Control Bonds	1,747	2,190
First Mortgage Bonds	-	19
Notes Payable	258	311
Securitization Bonds	2,183	2,257
Junior Subordinated Debentures	315	-
Notes Payable To Trust	113	113
Spent Nuclear Fuel Obligation (a)	262	259
Other Long-term Debt	3	2
Unamortized Discount (net)	(68)	(62)
Total Long-term Debt Outstanding	15,753	14,994
Less Portion Due Within One Year	569	792
Long-term Portion	$ 15,184	$ 14,202

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation of $294 million and $285 million at June 30, 2008 and December 31, 2007, respectively, are included in Spent Nuclear Fuel and Decommissioning Trusts on our Condensed Consolidated Balance Sheets.

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

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Issuances:				
AEP	Junior Subordinated Debentures	$ 315	8.75	2063
APCo	Pollution Control Bonds	75	Variable	2036
APCo	Pollution Control Bonds	50	Variable	2036
APCo	Senior Unsecured Notes	500	7.00	2038
CSPCo	Senior Unsecured Notes	350	6.05	2018
I&M	Pollution Control Bonds	25	Variable	2019
I&M	Pollution Control Bonds	52	Variable	2021
I&M	Pollution Control Bonds	40	5.25	2025
OPCo	Pollution Control Bonds	50	Variable	2014
OPCo	Pollution Control Bonds	50	Variable	2014
OPCo	Pollution Control Bonds	65	Variable	2036
SWEPCo	Senior Unsecured Notes	400	6.45	2019
Non-Registrant:				
TCC	Pollution Control Bonds	41	5.625	2017
TCC	Pollution Control Bonds	120	5.125	2030
TNC	Senior Unsecured Notes	30	5.89	2018
TNC	Senior Unsecured Notes	70	6.76	2038
Total Issuances		$ 2,233(a)		

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

(a) Amount indicated on statement of cash flows of $2,204 million is net of issuance costs and premium or discount.

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

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Senior Unsecured Notes	$ 200	3.60	2008
APCo	Pollution Control Bonds	40	Variable	2019
APCo	Pollution Control Bonds	30	Variable	2019
APCo	Pollution Control Bonds	18	Variable	2021
APCo	Pollution Control Bonds	50	Variable	2036
APCo	Pollution Control Bonds	75	Variable	2037
CSPCo	Senior Unsecured Notes	60	6.55	2008
CSPCo	Senior Unsecured Notes	52	6.51	2008
CSPCo	Pollution Control Bonds	48	Variable	2038
CSPCo	Pollution Control Bonds	44	Variable	2038
I&M	Pollution Control Bonds	45	Variable	2009
I&M	Pollution Control Bonds	25	Variable	2019
I&M	Pollution Control Bonds	52	Variable	2021
I&M	Pollution Control Bonds	50	Variable	2025
I&M	Pollution Control Bonds	50	Variable	2025
I&M	Pollution Control Bonds	40	Variable	2025
OPCo	Notes Payable	1	6.81	2008
OPCo	Notes Payable	6	6.27	2009
OPCo	Pollution Control Bonds	50	Variable	2014
OPCo	Pollution Control Bonds	50	Variable	2016
OPCo	Pollution Control Bonds	50	Variable	2022
OPCo	Pollution Control Bonds	35	Variable	2022
OPCo	Pollution Control Bonds	65	Variable	2036
PSO	Pollution Control Bonds	34	Variable	2014
SWEPCo	Notes Payable	2	Variable	2008
SWEPCo	Notes Payable	2	4.47	2011
Non-Registrant:				
AEP Subsidiaries	Notes Payable	4	5.88	2011
AEP Subsidiaries	Notes Payable	2	Variable	2017
AEGCo	Senior Unsecured Notes	4	6.33	2037
AEPSC	Mortgage Notes	34	9.60	2008
TCC	First Mortgage Bonds	19	7.125	2008
TCC	Securitization Bonds	29	5.01	2008
TCC	Securitization Bonds	45	4.98	2010
TCC	Pollution Control Bonds	41	Variable	2015
TCC	Pollution Control Bonds	60	Variable	2028
TCC	Pollution Control Bonds	60	Variable	2028
Total Retirements and Principal Payments		$ 1,472		

As of June 30, 2008, we had $313 million outstanding of tax-exempt long-term debt sold at auction rates that reset every 35 days. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation and Financial Guaranty Insurance Co. Due to the exposure that these bond insurers have in connection with developments in the subprime credit market, the credit ratings of these insurers have been downgraded or placed on negative outlook. These market factors have contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including many of the auctions of our tax-exempt long-term debt. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. Through June 30, 2008, we reduced our outstanding auction rate securities by $1.2 billion. We plan to continue the conversion and refunding process for the remaining $313 million to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, during the second half of 2008 to lower our interest rates as such opportunities arise.

As of June 30, 2008, $367 million of the prior auction rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 1.45% to 1.68% and $384 million was issued at fixed rates ranging from 4.85% to 5.625%. As of June 30, 2008, trustees held, on our behalf, approximately $400 million of our reacquired auction rate tax-exempt long-term debt which we plan to reissue to the public as market conditions permit.

Dividend Restrictions

We have the option to defer interest payments on the AEP Junior Subordinated Debentures issued in March 2008 for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our results of operations, cash flows, financial condition or limit any dividend payments in the foreseeable future.

Short-term Debt

Our outstanding short-term debt is as follows:

	June 30, 2008		December 31, 2007	
Type of Debt	**Outstanding Amount (in thousands)**	**Interest Rate (a)**	**Outstanding Amount (in thousands)**	**Interest Rate (a)**
Commercial Paper – AEP	$ 697,974	3.22 %	$ 659,135	5.54 %
Commercial Paper – JMG (b)	-	-	701	5.35 %
Line of Credit – Sabine Mining Company (c)	7,039	3.25 %	285	5.25 %
Total	$ 705,013		$ 660,121	

(a) Weighted average rate.
(b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce available liquidity under AEP's credit facilities.
(c) Sabine Mining Company is consolidated under FIN 46R. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

As of June 30, 2008, we had two $1.5 billion credit facilities to support our commercial paper program. In March 2008, the credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. Under the facilities, we may issue letters of credit. As of June 30, 2008, $371 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate demand notes.

10. SUBSEQUENT EVENT

In July 2008, TCC suffered damages in its southern Texas service territory related to Hurricane Dolly. Management is currently developing an estimate of the storm recovery costs related to Hurricane Dolly, but does not believe that these costs will have a material effect on future results of operations due to expected recovery in rates.

APPALACHIAN POWER COMPANY

AND SUBSIDIARIES

Results of Operations

Second Quarter of 2008 Compared to Second Quarter of 2007

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

Second Quarter of 2007		$	3
Changes in Gross Margin:			
Retail Margins	48		
Off-system Sales	8		
Other	(1)		
Total Change in Gross Margin			55
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	6		
Depreciation and Amortization	(31)		
Taxes Other Than Income Taxes	(1)		
Carrying Costs Income	6		
Other Income	4		
Interest Expense	(2)		
Total Change in Operating Expenses and Other			(18)
Income Tax Expense			(14)
Second Quarter of 2008		$	26

Income Before Extraordinary Loss increased $23 million to $26 million in 2008. The key drivers of the increase were a $55 million increase in Gross Margin partially offset by an increase in Operating Expenses and Other of $18 million and an increase in Income Tax Expense of $14 million.

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

- Retail Margins increased $48 million primarily due to the impact of the Virginia base rate order issued in May 2007 which included a second quarter 2007 provision for revenue refund in addition to an increase in the recovery of E&R costs in Virginia and construction financing costs in West Virginia. These increases were partially offset by an increase in sharing of off-system sales margins with customers and higher capacity settlement expenses under the Interconnection Agreement.
- Margins from Off-system Sales increased $8 million primarily due to higher physical sales margins partially offset by lower trading margins.

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

- Other Operation and Maintenance expenses decreased $6 million primarily due to a $3 million decrease in expenses associated with the Transmission Equalization Agreement and a $3 million decrease in uncollectible accounts receivable expense.
- Depreciation and Amortization expenses increased $31 million primarily due to favorable adjustments made in the second quarter of 2007 for the Virginia Rate Base order of $22 million and an increase in the amortization of carrying charges and depreciation expense of $6 million that are being collected through the Virginia E&R surcharges.
- Carrying Costs Income increased $6 million due to an increase in Virginia E&R deferrals.
- Interest Expense increased $2 million primarily due to an $11 million increase in interest expense from long-term debt issuances. This increase was partially offset by a $4 million favorable increase in allowance for borrowed funds used during construction and a $3 million decrease in interest related to the Virginia provision for refund recorded in the second quarter of 2007.
- Income Tax Expense increased $14 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

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

Six Months Ended June 30, 2007		$ 74
Changes in Gross Margin:		
Retail Margins	29	
Off-system Sales	24	
Transmission Revenues	1	
Other	(2)	
Total Change in Gross Margin		52
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(14)	
Depreciation and Amortization	(34)	
Taxes Other Than Income Taxes	(4)	
Carrying Costs Income	13	
Other Income	4	
Interest Expense	(14)	
Total Change in Operating Expenses and Other		(49)
Income Tax Expense		5
Six Months Ended June 30, 2008		$ 82

Income Before Extraordinary Loss increased $8 million to $82 million in 2008. The key drivers of the increase were a $52 million increase in Gross Margin partially offset by a $49 million increase in Operating Expenses and Other.

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

- Retail Margins increased $29 million primarily due to the impact of the Virginia base rate order issued in May 2007 which included a second quarter 2007 provision for revenue refund in addition to an increase in the recovery of E&R costs in Virginia and construction financing costs in West Virginia. These increases were partially offset by an increase in sharing of off-system sales margins with customers and higher capacity settlement expenses under the Interconnection Agreement.
- Margins from Off-system Sales increased $24 million primarily due to higher physical sales margins partially offset by lower trading margins.

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

- Other Operation and Maintenance expenses increased $14 million primarily due to a $6 million increase in distribution maintenance expenses resulting from repairs from storm damage. In addition, steam maintenance expenses increased $5 million due to a planned outage at the Mountaineer Plant in March 2008.
- Depreciation and Amortization expenses increased $34 million primarily due to favorable adjustments made in the second quarter 2007 for the Virginia base rate order of $22 million and the amortization of carrying charges and depreciation expense of $9 million that are being collected through the Virginia E&R surcharges.
- Taxes Other Than Income Taxes increased $4 million primarily due to favorable franchise tax return adjustments recorded in 2007.
- Carrying Costs Income increased $13 million due to an increase in Virginia E&R deferrals.
- Interest Expense increased $14 million primarily due to a $19 million increase in interest expense from long-term debt issuances partially offset by a $4 million decrease in interest on the Virginia provision for refund recorded in the second quarter of 2007.
- Income Tax Expense decreased $5 million primarily due to a decrease in state income taxes partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

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

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

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

Cash Flow

Cash flows for the six months ended June 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,195	$ 2,318
Cash Flows from (Used for):		
Operating Activities	140,378	265,414
Investing Activities	(296,095)	(378,985)
Financing Activities	155,398	112,605
Net Decrease in Cash and Cash Equivalents	(319)	(966)
Cash and Cash Equivalents at End of Period	$ 1,876	$ 1,352

Operating Activities

Net Cash Flows from Operating Activities were $140 million in 2008. APCo produced income of $82 million during the period and had noncash expense items of $124 million for Depreciation and Amortization, $72 million for Deferred Income Taxes and $27 million for Carrying Costs Income. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items in 2008. The $41 million cash inflow from Accounts Payable was primarily due to an increase in fuel costs. The $77 million cash outflow from Fuel Over/Under-Recovery, Net resulted in a net under recovery of fuel cost in both Virginia and West Virginia due to higher fuel costs.

Net Cash Flows from Operating Activities were $265 million in 2007. APCo incurred a Net Loss of $5 million during the period and had noncash expense items of $90 million for Depreciation and Amortization and $79 million for Extraordinary Loss for the Reapplication of Regulatory Accounting for Generation and $105 million for Regulatory Provision related to the Virginia base rate case. The other changes in assets and liabilities represent items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital had no significant items in 2007.

Investing Activities

Net Cash Flows Used for Investing Activities during 2008 and 2007 were $296 million and $379 million, respectively. Construction Expenditures were $312 million and $383 million in 2008 and 2007, respectively, primarily related to transmission and distribution service reliability projects, as well as environmental upgrades for both periods. Environmental upgrades includes the installation of the flue gas desulfurization equipment at the Amos and Mountaineer Plants. In February 2007, environmental upgrades were completed for the Mountaineer Plant. For the remainder of 2008, APCo expects construction expenditures to be approximately $458 million.

Financing Activities

Net Cash Flows from Financing Activities were $155 million in 2008. APCo received a capital contribution from Parent of $125 million. APCo issued $500 million of Senior Unsecured Notes in March 2008 and $125 million of Pollution Control Bonds in June 2008. These increases were partially offset by the retirement of $213 million of Pollution Control Bonds and the retirement of $200 million of Senior Unsecured Notes in the second quarter of 2008. In addition, APCo had a net decrease of $171 million in borrowings from the Utility Money Pool.

Net Cash Flows from Financing Activities in 2007 were $113 million primarily due to an increase of $213 million in borrowings from the Utility Money Pool and the issuance of $75 million of Pollution Control Bonds. These increases were partially offset by the retirement of $125 million of Senior Notes and payment of $25 million in dividends on common stock.

Financing Activity

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

Issuances

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

Retirements and Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Pollution Control Bonds	$ 40,000	Variable	2019
Pollution Control Bonds	17,500	Variable	2021
Pollution Control Bonds	30,000	Variable	2019
Pollution Control Bonds	50,275	Variable	2036
Pollution Control Bonds	75,000	Variable	2037
Senior Unsecured Notes	200,000	3.60	2008
Other	7	13.718	2026

Liquidity

APCo has solid investment grade ratings, which provide ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, APCo participates in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of contractual obligations is included in the 2007 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" and "Financing Activity" above and letters of credit. In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. As of June 30, 2008, $127 million of letters of credit were issued by APCo under the 3-year credit agreement to support variable rate demand notes.

Significant Factors

Litigation and Regulatory Activity

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

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

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

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

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 219,254	$ 3,871	$ -	$ (15,261)	$ 207,864
Noncurrent Assets	114,005	363	-	(8,538)	105,830
Total MTM Derivative Contract Assets	333,259	4,234	-	(23,799)	313,694
Current Liabilities	(223,908)	(28,732)	(3,396)	17,200	(238,836)
Noncurrent Liabilities	(80,869)	(1,287)	(3,720)	2,519	(83,357)
Total MTM Derivative Contract Liabilities	(304,777)	(30,019)	(7,116)	19,719	(322,193)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 28,482	$ (25,785)	$ (7,116)	$ (4,080)	$ (8,499)

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$	45,870
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(8,933)
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		1,151
Changes in Fair Value Due to Market Fluctuations During the Period (c)		(408)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		(9,198)
Total MTM Risk Management Contract Net Assets		28,482
Net Cash Flow & Fair Value Hedge Contracts		(25,785)
DETM Assignment (e)		(7,116)
Collateral Deposits		(4,080)
Ending Net Risk Management Assets at June 30, 2008	$	(8,499)

(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.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

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

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

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ (2,770)	$ 471	$ (21)	$ -	$ -	$ -	$ (2,320)
Level 2 (b)	2,314	12,244	12,956	5,150	1,782	-	34,446
Level 3 (c)	(9,305)	(1,566)	(3,892)	(2,504)	(1,293)	-	(18,560)
Total	(9,761)	11,149	9,043	2,646	489	-	13,566
Dedesignated Risk Management Contracts (d)	2,380	4,602	4,565	1,778	1,591	-	14,916
Total MTM Risk Management Contract Net Assets (Liabilities)	$ (7,381)	$ 15,751	$ 13,608	$ 4,424	$ 2,080	$ -	$ 28,482

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

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

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

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

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

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

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

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

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

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

	Power	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2007	$ 783	$ (6,602)	$ (125)	$ (5,944)
Changes in Fair Value	(15,824)	(3,114)	75	(18,863)
Reclassifications from AOCI for Cash Flow Hedges Settled	(682)	813	3	134
Ending Balance in AOCI June 30, 2008	$ (15,723)	$ (8,903)	$ (47)	$ (24,673)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $16.8 million loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

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

Six Months Ended June 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$603	$1,002	$391	$161	$455	$2,328	$569	$117

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

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which APCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on APCo's debt portfolio was $5.2 million.

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

	Three Months Ended 2008	Three Months Ended 2007	Six Months Ended 2008	Six Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 566,089	$ 499,189	$ 1,207,546	$ 1,100,735
Sales to AEP Affiliates	97,508	55,371	187,598	116,916
Other	3,800	2,850	7,280	5,487
TOTAL	667,397	557,410	1,402,424	1,223,138
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	159,237	164,018	333,067	335,204
Purchased Electricity for Resale	52,931	34,328	96,130	70,278
Purchased Electricity from AEP Affiliates	186,243	144,630	375,838	272,231
Other Operation	68,415	75,125	143,946	142,754
Maintenance	52,235	51,414	110,079	97,167
Depreciation and Amortization	61,592	31,076	124,164	90,236
Taxes Other Than Income Taxes	24,104	22,975	48,095	44,250
TOTAL	604,757	523,566	1,231,319	1,052,120
OPERATING INCOME	62,640	33,844	171,105	171,018
Other Income (Expense):				
Interest Income	2,827	390	5,596	1,029
Carrying Costs Income	17,411	10,950	26,997	14,116
Allowance for Equity Funds Used During Construction	2,652	1,581	4,148	4,358
Interest Expense	(47,119)	(44,955)	(91,259)	(76,778)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT)	38,411	1,810	116,587	113,743
Income Tax Expense (Credit)	12,129	(1,471)	34,992	40,235
INCOME BEFORE EXTRAORDINARY LOSS	26,282	3,281	81,595	73,508
Extraordinary Loss – Reapplication of Regulatory Accounting for Generation, Net of Tax	-	(78,763)	-	(78,763)
NET INCOME (LOSS)	26,282	(75,482)	81,595	(5,255)
Preferred Stock Dividend Requirements Including Capital Stock Expense	238	238	476	476
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 26,044	$ (75,720)	$ 81,119	$ (5,731)

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 Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 260,458	$ 1,024,994	$ 805,513	$ (54,791)	$ 2,036,174
FIN 48 Adoption, Net of Tax			(2,685)		(2,685)
Common Stock Dividends			(25,000)		(25,000)
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense		76	(76)		-
TOTAL					2,008,089
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,482				4,610	4,610
SFAS 158 Costs Established as a Regulatory Asset Related to the Reapplication of SFAS 71, Net of Tax of $6,055				11,245	11,245
NET LOSS			(5,255)		(5,255)
TOTAL COMPREHENSIVE INCOME					10,600
JUNE 30, 2007	$ 260,458	$ 1,025,070	$ 772,097	$ (38,936)	$ 2,018,689
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		125,000			125,000
Preferred Stock Dividends			(399)		(399)
Capital Stock Expense		77	(77)		-
TOTAL					2,204,166
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $10,085				(18,729)	(18,729)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $897				1,666	1,666
NET INCOME			81,595		81,595
TOTAL COMPREHENSIVE INCOME					64,532
JUNE 30, 2008	$ 260,458	$ 1,150,226	$ 910,264	$ (52,250)	$ 2,268,698

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
June 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,876	$ 2,195
Accounts Receivable:		
Customers	198,958	176,834
Affiliated Companies	79,810	113,582
Accrued Unbilled Revenues	34,213	38,397
Miscellaneous	592	2,823
Allowance for Uncollectible Accounts	(5,835)	(13,948)
Total Accounts Receivable	307,738	317,688
Fuel	84,139	82,203
Materials and Supplies	80,244	76,685
Risk Management Assets	207,864	62,955
Regulatory Asset for Under-Recovered Fuel Costs	53,399	-
Prepayments and Other	51,831	16,369
TOTAL	787,091	558,095
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,633,832	3,625,788
Transmission	1,712,793	1,675,081
Distribution	2,429,600	2,372,687
Other	356,089	351,827
Construction Work in Progress	856,270	713,063
Total	8,988,584	8,738,446
Accumulated Depreciation and Amortization	2,639,155	2,591,833
TOTAL - NET	6,349,429	6,146,613
OTHER NONCURRENT ASSETS		
Regulatory Assets	683,609	652,739
Long-term Risk Management Assets	105,830	72,366
Deferred Charges and Other	197,938	191,871
TOTAL	987,377	916,976
TOTAL ASSETS	$ 8,123,897	$ 7,621,684

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

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

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 103,802	$ 275,257
Accounts Payable:		
General	281,893	241,871
Affiliated Companies	99,692	106,852
Long-term Debt Due Within One Year – Nonaffiliated	150,016	239,732
Risk Management Liabilities	238,836	51,708
Customer Deposits	50,978	45,920
Accrued Taxes	48,527	58,519
Accrued Interest	46,693	41,699
Other	99,752	139,476
TOTAL	1,120,189	1,201,034
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,803,466	2,507,567
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	83,357	47,357
Deferred Income Taxes	1,013,394	948,891
Regulatory Liabilities and Deferred Investment Tax Credits	490,350	505,556
Deferred Credits and Other	226,691	211,495
TOTAL	4,717,258	4,320,866
TOTAL LIABILITIES	5,837,447	5,521,900
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,752	17,752
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,150,226	1,025,149
Retained Earnings	910,264	831,612
Accumulated Other Comprehensive Income (Loss)	(52,250)	(35,187)
TOTAL	2,268,698	2,082,032
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 8,123,897	$ 7,621,684

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

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

	2008	2007
OPERATING ACTIVITIES		
Net Income (Loss)	$ 81,595	$ (5,255)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	124,164	90,236
Deferred Income Taxes	71,728	(17,439)
Extraordinary Loss, Net of Tax	-	78,763
Regulatory Provision	-	105,110
Carrying Costs Income	(26,997)	(14,116)
Allowance for Equity Funds Used During Construction	(4,148)	(4,358)
Mark-to-Market of Risk Management Contracts	17,298	5,457
Change in Other Noncurrent Assets	(14,006)	(7,896)
Change in Other Noncurrent Liabilities	(20,038)	(1,239)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	2,583	31,483
Fuel, Materials and Supplies	(5,495)	(20,654)
Accounts Payable	40,905	(26,786)
Accrued Taxes, Net	(31,213)	39,168
Fuel Over/Under-Recovery, Net	(77,036)	15,221
Other Current Assets	(14,225)	3,140
Other Current Liabilities	(4,737)	(5,421)
Net Cash Flows from Operating Activities	140,378	265,414
INVESTING ACTIVITIES		
Construction Expenditures	(311,550)	(382,501)
Change in Other Cash Deposits, Net	(15)	(2,678)
Proceeds from Sales of Assets	15,470	6,194
Net Cash Flows Used for Investing Activities	(296,095)	(378,985)
FINANCING ACTIVITIES		
Capital Contribution from Parent	125,000	-
Issuance of Long-term Debt – Nonaffiliated	617,111	73,438
Change in Advances from Affiliates, Net	(171,455)	212,641
Retirement of Long-term Debt – Nonaffiliated	(412,782)	(125,006)
Principal Payments for Capital Lease Obligations	(2,077)	(2,200)
Amortization of Funds From Amended Coal Contract	-	(20,868)
Dividends Paid on Common Stock	-	(25,000)
Dividends Paid on Cumulative Preferred Stock	(399)	(400)
Net Cash Flows from Financing Activities	155,398	112,605
Net Decrease in Cash and Cash Equivalents	(319)	(966)
Cash and Cash Equivalents at Beginning of Period	2,195	2,318
Cash and Cash Equivalents at End of Period	$ 1,876	$ 1,352
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 86,873	$ 69,823
Net Cash Paid (Received) for Income Taxes	(10,708)	6,197
Noncash Acquisitions Under Capital Leases	1,014	1,693
Construction Expenditures Included in Accounts Payable at June 30,	98,958	97,044

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2008 Compared to Second Quarter of 2007

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

Second Quarter of 2007		$ 80
Changes in Gross Margin:		
Retail Margins	(13)	
Off-system Sales	10	
Transmission Revenues	1	
Total Change in Gross Margin		(2)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(30)	
Depreciation and Amortization	2	
Taxes Other Than Income Taxes	(5)	
Interest Expense	(1)	
Other	1	
Total Change in Operating Expenses and Other		(33)
Income Tax Expense		11
Second Quarter of 2008		$ 56

Net Income decreased $24 million to $56 million in 2008. The key drivers of the decrease were a $33 million increase in Operating Expenses and Other partially offset by an $11 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 $13 million primarily due to:
  - A $32 million decrease related to increased fuel and PJM expenses.
  - A $12 million decrease in residential and commercial revenue primarily due to a 55% decrease in heating degree days and a 24% decrease in cooling degree days.

  These decreases were partially offset by:
  - A $26 million increase related to a net increase in rates implemented.
  - A $7 million decrease in capacity purchases related to CSPCo's unit power agreement for AEGCo's Lawrenceburg Plant which began in May 2007 and the April 2007 acquisition of the Darby Plant.
  - A $4 million increase in industrial revenue due to increased usage by Ormet, a major industrial customer.
- Margins from Off-system Sales increased $10 million primarily due to higher physical sales margins and higher trading margins.

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

- Other Operation and Maintenance expenses increased $30 million due to:
  - A $9 million increase in recoverable PJM costs.
  - An $8 million increase in steam plant maintenance expenses primarily related to work performed at the Conesville Plant.
  - A $4 million increase in boiler plant removal expenses primarily related to work performed at the Conesville Plant.
  - A $4 million increase in expenses related to CSPCo's unit power agreement for AEGCo's Lawrenceburg Plant which began in May 2007.
  - A $3 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
- Depreciation and Amortization decreased $2 million primarily due to the amortization of IGCC pre-construction costs, which ended in the second quarter of 2007. The amortization of IGCC pre-construction costs was offset by a corresponding increase in Retail Margins in 2007.
- Taxes Other Than Income Taxes increased $5 million due to property tax adjustments.
- Income Tax Expense decreased $11 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Reconciliation of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2008
Net Income
(in millions)

Six Months Ended June 30, 2007		$ 127
Changes in Gross Margin:		
Retail Margins	40	
Off-system Sales	20	
Transmission Revenues	1	
Total Change in Gross Margin		61
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(43)	
Depreciation and Amortization	4	
Taxes Other Than Income Taxes	(9)	
Other Income	5	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		(48)
Income Tax Expense		(7)
Six Months Ended June 30, 2008		$ 133

Net Income increased $6 million to $133 million in 2008. The key drivers of the increase were a $61 million increase in Gross Margin primarily offset by a $48 million increase in Operating Expenses and Other and a $7 million increase in Income Tax Expense.

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

- Retail Margins increased $40 million primarily due to:
  - A $58 million increase related to a net increase in rates implemented.
  - A $39 million decrease in capacity settlement charges related to CSPCo's unit power agreement for AEGCo's Lawrenceburg Plant which began in May 2007 and the April 2007 acquisition of the Darby Plant.
  - A $15 million increase in industrial revenue due to increased usage by Ormet, a major industrial customer.

  These increases were partially offset by:
  - A $60 million decrease related to increased fuel and PJM expenses.
  - A $9 million decrease in residential and commercial revenue primarily due to a 25% decrease in cooling degree days.
- Margins from Off-system Sales increased $20 million primarily due to higher physical sales margins and higher trading margins.

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

- Other Operation and Maintenance expenses increased $43 million primarily due to:
  - A $13 million increase in expenses related to CSPCo's unit power agreement for AEGCo's Lawrenceburg Plant which began in May 2007.
  - A $12 million increase in steam plant maintenance expenses primarily related to work performed at the Conesville Plant.
  - An $8 million increase in recoverable PJM expenses.
  - A $5 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $3 million increase in boiler plant removal expenses primarily related to work performed at the Conesville Plant.
- Depreciation and Amortization decreased $4 million primarily due to a $6 million decrease in amortization of IGCC pre-construction costs offset by a $3 million increase related to the acquisition of the Darby Plant in 2007.
- Taxes Other Than Income Taxes increased $9 million due to property tax adjustments.
- Interest Expense increased $5 million due to increased long-term borrowings and an increase in short-term borrowings from the Utility Money Pool.
- Income Tax Expense increased $7 million primarily due to an increase in pretax book income and state income taxes.

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which CSPCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on CSPCo's debt portfolio was $2.1 million.

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

	Three Months Ended		Six Months Ended	
	2008	2007	2008	2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 500,056	$ 469,648	$ 1,005,380	$ 893,114
Sales to AEP Affiliates	47,413	35,356	82,521	58,369
Other	1,478	1,018	2,695	2,451
TOTAL	548,947	506,022	1,090,596	953,934
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	86,253	76,342	171,380	152,204
Purchased Electricity for Resale	45,010	32,835	87,196	64,146
Purchased Electricity from AEP Affiliates	110,578	87,788	204,682	171,329
Other Operation	84,955	62,516	158,021	123,675
Maintenance	34,435	26,723	57,666	49,287
Depreciation and Amortization	47,693	49,446	96,295	99,743
Taxes Other Than Income Taxes	40,989	35,796	85,545	76,378
TOTAL	449,913	371,446	860,785	736,762
OPERATING INCOME	99,034	134,576	229,811	217,172
Other Income (Expense):				
Interest Income	1,603	194	3,942	616
Carrying Costs Income	1,538	1,139	3,304	2,231
Allowance for Equity Funds Used During Construction	565	620	1,420	1,392
Interest Expense	(17,246)	(16,382)	(36,485)	(31,663)
INCOME BEFORE INCOME TAX EXPENSE	85,494	120,147	201,992	189,748
Income Tax Expense	29,101	40,125	69,446	62,745
NET INCOME	56,393	80,022	132,546	127,003
Capital Stock Expense	40	40	79	79
EARNINGS APPLICABLE TO COMMON STOCK	$ 56,353	$ 79,982	$ 132,467	$ 126,924

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 Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 41,026	$ 580,192	$ 456,787	$ (21,988)	$ 1,056,017
FIN 48 Adoption, Net of Tax			(3,022)		(3,022)
Common Stock Dividends			(40,000)		(40,000)
Capital Stock Expense		79	(79)		-
TOTAL					1,012,995
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $360				669	669
NET INCOME			127,003		127,003
TOTAL COMPREHENSIVE INCOME					127,672
JUNE 30, 2007	$ 41,026	$ 580,271	$ 540,689	$ (21,319)	$ 1,140,667
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			(62,500)		(62,500)
Capital Stock Expense		79	(79)		-
TOTAL					1,100,366
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $5,090				(9,451)	(9,451)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $304				564	564
NET INCOME			132,546		132,546
TOTAL COMPREHENSIVE INCOME					123,659
JUNE 30, 2008	$ 41,026	$ 580,428	$ 630,252	$ (27,681)	$ 1,224,025

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
June 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,591	$ 1,389
Other Cash Deposits	36,975	53,760
Advances to Affiliates	25,199	-
Accounts Receivable:		
Customers	78,715	57,268
Affiliated Companies	20,346	32,852
Accrued Unbilled Revenues	18,759	14,815
Miscellaneous	15,238	9,905
Allowance for Uncollectible Accounts	(2,647)	(2,563)
Total Accounts Receivable	130,411	112,277
Fuel	37,196	35,849
Materials and Supplies	37,191	36,626
Emission Allowances	11,766	16,811
Risk Management Assets	111,622	33,558
Prepayments and Other	17,153	9,960
TOTAL	409,104	300,230
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,135,486	2,072,564
Transmission	563,847	510,107
Distribution	1,577,693	1,552,999
Other	205,097	198,476
Construction Work in Progress	464,286	415,327
Total	4,946,409	4,749,473
Accumulated Depreciation and Amortization	1,749,038	1,697,793
TOTAL - NET	3,197,371	3,051,680
OTHER NONCURRENT ASSETS		
Regulatory Assets	218,323	235,883
Long-term Risk Management Assets	61,708	41,852
Deferred Charges and Other	146,808	181,563
TOTAL	426,839	459,298
TOTAL ASSETS	$ 4,033,314	$ 3,811,208

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

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

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 95,199
Accounts Payable:		
General	150,298	113,290
Affiliated Companies	57,025	65,292
Long-term Debt Due Within One Year – Nonaffiliated	-	112,000
Risk Management Liabilities	131,260	28,237
Customer Deposits	45,190	43,095
Accrued Taxes	154,288	179,831
Other	85,794	96,892
TOTAL	623,855	733,836
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,343,388	1,086,224
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	49,103	27,419
Deferred Income Taxes	440,884	437,306
Regulatory Liabilities and Deferred Investment Tax Credits	159,635	165,635
Deferred Credits and Other	92,424	96,511
TOTAL	2,185,434	1,913,095
TOTAL LIABILITIES	2,809,289	2,646,931
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,428	580,349
Retained Earnings	630,252	561,696
Accumulated Other Comprehensive Income (Loss)	(27,681)	(18,794)
TOTAL	1,224,025	1,164,277
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 4,033,314	$ 3,811,208

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

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

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 132,546	$ 127,003
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	96,295	99,743
Deferred Income Taxes	9,670	(5,077)
Carrying Costs Income	(3,304)	(2,231)
Allowance for Equity Funds Used During Construction	(1,420)	(1,392)
Mark-to-Market of Risk Management Contracts	10,859	6,842
Deferred Property Taxes	43,745	39,063
Change in Other Noncurrent Assets	(19,046)	(24,593)
Change in Other Noncurrent Liabilities	(2,759)	(7,054)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(18,134)	7,678
Fuel, Materials and Supplies	(1,912)	(8,896)
Accounts Payable	8,747	(10,735)
Customer Deposits	2,095	15,616
Accrued Taxes, Net	(25,530)	5,493
Other Current Assets	(2,160)	8,601
Other Current Liabilities	(13,657)	(1,952)
Net Cash Flows from Operating Activities	216,035	248,109
INVESTING ACTIVITIES		
Construction Expenditures	(191,668)	(169,014)
Change in Other Cash Deposits, Net	16,785	(20)
Change in Advances to Affiliates, Net	(25,199)	-
Acquisition of Darby Plant	-	(102,032)
Proceeds from Sales of Assets	700	842
Net Cash Flows Used for Investing Activities	(199,382)	(270,224)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	346,934	-
Change in Advances from Affiliates, Net	(95,199)	63,307
Retirement of Long-term Debt – Nonaffiliated	(204,245)	-
Principal Payments for Capital Lease Obligations	(1,441)	(1,446)
Dividends Paid on Common Stock	(62,500)	(40,000)
Net Cash Flows from (Used for) Financing Activities	(16,451)	21,861
Net Increase (Decrease) in Cash and Cash Equivalents	202	(254)
Cash and Cash Equivalents at Beginning of Period	1,389	1,319
Cash and Cash Equivalents at End of Period	$ 1,591	$ 1,065
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 38,531	$ 31,557
Net Cash Paid for Income Taxes	22,307	1,704
Noncash Acquisitions Under Capital Leases	1,228	1,347
Construction Expenditures Included in Accounts Payable at June 30,	62,157	30,659
Noncash Assumption of Liabilities Related to Acquisition of Darby Plant	-	2,339

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

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

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

INDIANA MICHIGAN POWER COMPANY

AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2008 Compared to Second Quarter of 2007

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

Second Quarter of 2007		$ 30
Changes in Gross Margin:		
Retail Margins	(3)	
FERC Municipals and Cooperatives	3	
Off-system Sales	5	
Other	10	
Total Change in Gross Margin		15
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(14)	
Depreciation and Amortization	22	
Taxes Other Than Income Taxes	(1)	
Interest Expense	3	
Total Change in Operating Expenses and Other		10
Income Tax Expense		(5)
Second Quarter of 2008		$ 50

Net Income increased $20 million to $50 million in 2008. The key drivers of the increase were a $15 million increase in Gross Margin and a $10 million decrease in Operating Expenses and Other partially offset by a $5 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 lower retail sales reflecting weather conditions as cooling degree days decreased significantly in both the Indiana and Michigan jurisdictions.
- FERC Municipals and Cooperatives margins increased $3 million due to higher revenues under formula rate plans in 2008.
- Margins from Off-system Sales increased $5 million primarily due to higher physical sales margins partially offset by lower trading margins.
- Other revenues increased $10 million primarily due to increased River Transportation Division (RTD) revenues for barging services. RTD's related expenses which offset the RTD revenue increase are included in Other Operation on the Condensed Consolidated Statements of Income resulting in earning only a return approved under a regulatory order.

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

- Other Operation and Maintenance expenses increased $14 million primarily due to higher operation and maintenance expenses for RTD of $12 million caused by increased barging activity and increased cost of fuel. Nuclear operation and maintenance expense increases were offset by lower coal-fired plant maintenance expenses. Scheduled outages occurred at Cook Plant in 2008 and Rockport Plant in 2007.
- Depreciation and Amortization expense decreased $22 million primarily due to reduced depreciation rates reflecting longer estimated lives for Cook and Tanners Creek Plants. Depreciation rates were reduced for the Indiana jurisdiction in June 2007 and the FERC and Michigan jurisdictions in October 2007. See “Indiana Depreciation Study Filing” and “Michigan Depreciation Study Filing” sections of Note 4 in the 2007 Annual Report.
- Income Tax Expense increased $5 million primarily due to an increase in pretax book income and a decrease in amortization of investment tax credits partially offset by changes in certain book/tax differences accounted for on a flow-through basis and a decrease in state income tax.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Reconciliation of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2008
Net Income
(in millions)

Six Months Ended June 30, 2007		$ 59
Changes in Gross Margin:		
Retail Margins	(2)	
FERC Municipals and Cooperatives	7	
Off-system Sales	14	
Transmission Revenues	(1)	
Other	18	
Total Change in Gross Margin		36
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(23)	
Depreciation and Amortization	47	
Taxes Other Than Income Taxes	(3)	
Other Income	2	
Interest Expense	3	
Total Change in Operating Expenses and Other		26
Income Tax Expense		(16)
Six Months Ended June 30, 2008		$ 105

Net Income increased $46 million to $105 million in 2008. The key drivers of the increase were a $36 million increase in Gross Margin and a $26 million decrease in Operating Expenses and Other partially offset by a $16 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:

- FERC Municipals and Cooperatives margins increased $7 million due to higher revenues under formula rate plans in 2008.
- Margins from Off-system Sales increased $14 million primarily due to higher physical sales margins partially offset by lower trading margins.
- Other revenues increased $18 million primarily due to increased RTD revenues for barging services. RTD’s related expenses which offset the RTD revenue increase are included in Other Operation on the Condensed Consolidated Statements of Income resulting in earning only a return approved under regulatory order.

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

- Other Operation and Maintenance expenses increased $23 million primarily due to higher operation and maintenance expenses for RTD of $19 million caused by increased barging activity and increased cost of fuel. Nuclear operation and maintenance expense increases were offset by lower coal-fired plant maintenance and accretion expenses. Scheduled outages occurred at Cook Plant in 2008 and Rockport Plant in 2007.
- Depreciation and Amortization expense decreased $47 million primarily due to the reduced depreciation rates in all jurisdictions.
- Income Tax Expense increased $16 million primarily due to an increase in pretax book income and a decrease in amortization of investment tax credits partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which I&M's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on I&M's debt portfolio was $4.8 million.

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

	Three Months Ended 2008	Three Months Ended 2007	Six Months Ended 2008	Six Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 425,018	$ 402,152	$ 856,610	$ 807,316
Sales to AEP Affiliates	83,927	62,962	160,439	130,391
Other – Affiliated	29,257	14,571	52,476	27,238
Other – Nonaffiliated	4,445	6,352	10,271	13,961
TOTAL	542,647	486,037	1,079,796	978,906
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	108,496	90,650	209,737	186,767
Purchased Electricity for Resale	26,441	19,310	47,924	37,250
Purchased Electricity from AEP Affiliates	91,858	75,791	184,499	153,304
Other Operation	124,687	117,311	245,053	238,044
Maintenance	52,608	45,725	103,829	88,155
Depreciation and Amortization	31,757	53,890	63,479	110,197
Taxes Other Than Income Taxes	20,342	19,238	40,244	37,232
TOTAL	456,189	421,915	894,765	850,949
OPERATING INCOME	86,458	64,122	185,031	127,957
Other Income (Expense):				
Interest Income	1,904	707	2,733	1,295
Allowance for Equity Funds Used During Construction	128	727	1,008	992
Interest Expense	(17,146)	(19,611)	(36,348)	(39,432)
INCOME BEFORE INCOME TAX EXPENSE	71,344	45,945	152,424	90,812
Income Tax Expense	21,200	15,910	47,022	31,314
NET INCOME	50,144	30,035	105,402	59,498
Preferred Stock Dividend Requirements	85	85	170	170
EARNINGS APPLICABLE TO COMMON STOCK	$ 50,059	$ 29,950	$ 105,232	$ 59,328

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 Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 56,584	$ 861,290	$ 386,616	$ (15,051)	$ 1,289,439
FIN 48 Adoption, Net of Tax			327		327
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(170)		(170)
Gain on Reacquired Preferred Stock		1			1
TOTAL					1,269,597
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $649				1,206	1,206
NET INCOME			59,498		59,498
TOTAL COMPREHENSIVE INCOME					60,704
JUNE 30, 2007	$ 56,584	$ 861,291	$ 426,271	$ (13,845)	$ 1,330,301
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			(37,500)		(37,500)
Preferred Stock Dividends			(170)		(170)
TOTAL					1,346,631
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,618				(8,577)	(8,577)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $118				220	220
NET INCOME			105,402		105,402
TOTAL COMPREHENSIVE INCOME					97,045
JUNE 30, 2008	$ 56,584	$ 861,291	$ 549,833	$ (24,032)	$ 1,443,676

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
June 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 982	$ 1,139
Accounts Receivable:		
Customers	97,676	70,995
Affiliated Companies	62,238	92,018
Accrued Unbilled Revenues	13,432	16,207
Miscellaneous	1,080	1,335
Allowance for Uncollectible Accounts	(2,776)	(2,711)
Total Accounts Receivable	171,650	177,844
Fuel	56,541	61,342
Materials and Supplies	145,091	141,384
Risk Management Assets	105,164	32,365
Accrued Tax Benefits	10,619	4,438
Prepayments and Other	22,870	11,091
TOTAL	512,917	429,603
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,507,581	3,529,524
Transmission	1,094,164	1,078,575
Distribution	1,242,898	1,196,397
Other (including nuclear fuel and coal mining)	608,205	626,390
Construction Work in Progress	135,723	122,296
Total	6,588,571	6,553,182
Accumulated Depreciation, Depletion and Amortization	2,988,253	2,998,416
TOTAL - NET	3,600,318	3,554,766
OTHER NONCURRENT ASSETS		
Regulatory Assets	263,951	246,435
Spent Nuclear Fuel and Decommissioning Trusts	1,361,927	1,346,798
Long-term Risk Management Assets	58,516	40,227
Deferred Charges and Other	134,693	128,623
TOTAL	1,819,087	1,762,083
TOTAL ASSETS	$ 5,932,322	$ 5,746,452

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

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

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 272,707	$ 45,064
Accounts Payable:		
General	107,120	184,435
Affiliated Companies	47,603	61,749
Long-term Debt Due Within One Year – Nonaffiliated	50,000	145,000
Risk Management Liabilities	124,092	27,271
Customer Deposits	27,341	26,445
Accrued Taxes	73,783	60,995
Obligations Under Capital Leases	44,388	43,382
Other	108,766	130,232
TOTAL	855,800	724,573
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,375,757	1,422,427
Long-term Risk Management Liabilities	46,777	26,348
Deferred Income Taxes	370,242	321,716
Regulatory Liabilities and Deferred Investment Tax Credits	767,385	789,346
Asset Retirement Obligations	874,941	852,646
Deferred Credits and Other	189,664	215,617
TOTAL	3,624,766	3,628,100
TOTAL LIABILITIES	4,480,566	4,352,673
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,080	8,080
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	861,291	861,291
Retained Earnings	549,833	483,499
Accumulated Other Comprehensive Income (Loss)	(24,032)	(15,675)
TOTAL	1,443,676	1,385,699
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,932,322	$ 5,746,452

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

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

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 105,402	$ 59,498
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	63,479	110,197
Deferred Income Taxes	41,362	(9,547)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(8,576)	23,099
Allowance for Equity Funds Used During Construction	(1,008)	(992)
Mark-to-Market of Risk Management Contracts	10,862	6,903
Amortization of Nuclear Fuel	45,312	33,003
Change in Other Noncurrent Assets	(9,103)	(11,316)
Change in Other Noncurrent Liabilities	19,847	19,425
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	6,194	36,805
Fuel, Materials and Supplies	1,094	9,911
Accounts Payable	449	(46,049)
Accrued Taxes, Net	6,607	72,977
Other Current Assets	(11,777)	3,373
Other Current Liabilities	(23,583)	(16,388)
Net Cash Flows from Operating Activities	246,561	290,899
INVESTING ACTIVITIES		
Construction Expenditures	(140,537)	(124,252)
Purchases of Investment Securities	(276,031)	(409,163)
Sales of Investment Securities	241,079	370,986
Acquisitions of Nuclear Fuel	(98,732)	(30,498)
Proceeds from Sales of Assets and Other	2,912	292
Net Cash Flows Used for Investing Activities	(271,309)	(192,635)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	115,553	-
Change in Advances from Affiliates, Net	227,643	(76,232)
Retirement of Long-term Debt – Nonaffiliated	(262,000)	-
Retirement of Cumulative Preferred Stock	-	(2)
Principal Payments for Capital Lease Obligations	(18,935)	(2,622)
Dividends Paid on Common Stock	(37,500)	(20,000)
Dividends Paid on Cumulative Preferred Stock	(170)	(170)
Net Cash Flows from (Used for) Financing Activities	24,591	(99,026)
Net Decrease in Cash and Cash Equivalents	(157)	(762)
Cash and Cash Equivalents at Beginning of Period	1,139	1,369
Cash and Cash Equivalents at End of Period	$ 982	$ 607
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 38,706	$ 32,082
Net Cash Paid (Received) for Income Taxes	13,827	(20,001)
Noncash Acquisitions Under Capital Leases	2,911	1,160
Construction Expenditures Included in Accounts Payable at June 30,	20,650	24,145
Acquisition of Nuclear Fuel Included in Accounts Payable at June 30,	-	30,867

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

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2008 Compared to Second Quarter of 2007

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

Second Quarter of 2007		$ 74
Changes in Gross Margin:		
Retail Margins	(46)	
Off-system Sales	9	
Other	2	
Total Change in Gross Margin		(35)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(13)	
Depreciation and Amortization	14	
Taxes Other Than Income Taxes	4	
Other Income	2	
Interest Expense	(8)	
Total Change in Operating Expenses and Other		(1)
Income Tax Expense		15
Second Quarter of 2008		$ 53

Net Income decreased $21 million to $53 million in 2008. The key drivers of the decrease were a $35 million decrease in Gross Margin offset by a $15 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 $46 million primarily due to the following:
  - A $29 million decrease related to a coal contract amendment in the second quarter of 2008.
  - A $29 million decrease related to increased fuel, consumable, allowance and PJM expenses.
  - A $6 million decrease in residential revenue primarily due to a 27% decrease in cooling degree days and a 30% decrease in heating degree days.

  These decreases were partially offset by:
  - A $14 million increase related to a net increase in rates implemented.
- Margins from Off-system Sales increased $9 million due to higher physical sales margins partially offset by lower trading margins.

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

- Other Operation and Maintenance expenses increased $13 million primarily due to:
  - A $10 million increase in recoverable PJM expenses.
  - A $10 million increase in steam plant maintenance expenses.
  - A $3 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.

  These increases were partially offset by:
  - A $4 million decrease in overhead line maintenance expenses.
  - A $3 million decrease in removal expenses due to work performed at the Cardinal, Mitchell and Gavin Plants in 2007.
- Depreciation and Amortization decreased $14 million primarily due to:
  - A $17 million decrease in amortization as a result of completion of amortization of regulatory assets in December 2007.
  - A $3 million decrease due to the amortization of IGCC pre-construction costs, which ended in the second quarter of 2007. The amortization of IGCC pre-construction costs was offset by a corresponding increase in Retail Margins in 2007.

  These decreases were partially offset by:
  - A $6 million increase in depreciation related to environmental improvements placed in service at the Cardinal Plant in 2008 and the Mitchell Plant in July 2007.
- Taxes Other Than Income Taxes decreased $4 million primarily due to property tax adjustments.
- Interest Expense increased $8 million primarily due to a decrease in the debt component of AFUDC as a result of Mitchell Plant and Cardinal Plant environmental improvements placed in service and higher interest rates on variable rate debt.
- Income Tax Expense decreased $15 million primarily due to a decrease in pretax book income.

<u>Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007</u>

Reconciliation of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2008
Net Income
(in millions)

Six Months Ended June 30, 2007		$ 154
Changes in Gross Margin:		
Retail Margins	(6)	
Off-system Sales	23	
Other	9	
Total Change in Gross Margin		26
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	10	
Depreciation and Amortization	29	
Taxes Other Than Income Taxes	1	
Other Income	5	
Interest Expense	(16)	
Total Change in Operating Expenses and Other		29
Income Tax Expense		(18)
Six Months Ended June 30, 2008		$ 191

Net Income increased $37 million to $191 million in 2008. The key drivers of the increase were a $26 million increase in Gross Margin and a $29 million decrease in Operating Expenses and Other offset by an $18 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 $6 million primarily due to the following:
  - A $76 million decrease related to increased fuel, consumable and PJM expenses.
  - A $5 million decrease in residential and commercial revenues primarily due to a 28% decrease in cooling degree days.

  These decreases were partially offset by:
  - A $29 million increase related to coal contract amendments in 2008.
  - A $25 million increase related to a net increase in rates implemented.
  - A $15 million increase related to increased usage by Ormet, an industrial customer. See "Ormet" section of Note 3.
  - A $7 million increase in capacity settlements under the Interconnection Agreement related to an increase in an affiliate's peak.
- Margins from Off-system Sales increased $23 million due to higher physical sales margins and higher trading margins.
- Other revenues increased $9 million primarily due to increased gains on sales of emission allowances.

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

- Other Operation and Maintenance expenses decreased $10 million primarily due to:
  - A $21 million decrease in removal expenses.
  - A $9 million decrease in overhead line maintenance expenses.

  These decreases were partially offset by:
  - A $7 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $7 million increase in recoverable PJM expenses.
- Depreciation and Amortization decreased $29 million primarily due to:
  - A $35 million decrease in amortization as a result of completion of amortization of regulatory assets in December 2007.
  - A $6 million decrease due to the amortization of IGCC pre-construction costs, which ended in the second quarter of 2007. The amortization of IGCC pre-construction costs was offset by a corresponding increase in Retail Margins in 2007.

  These decreases were partially offset by:
  - A $14 million increase in depreciation related to environmental improvements placed in service at the Cardinal Plant in 2008 and the Mitchell Plant during 2007.
- Interest Expense increased $16 million primarily due to a decrease in the debt component of AFUDC as a result of Mitchell Plant and Cardinal Plant environmental improvements placed in service, the issuance of additional long-term debt and higher interest rates on variable rate debt.
- Income Tax Expense increased $18 million primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

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

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

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

Cash Flow

Cash flows for the six months ended June 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 6,666	$ 1,625
Cash Flows from (Used for):		
Operating Activities	289,944	279,029
Investing Activities	(271,527)	(560,262)
Financing Activities	(14,985)	282,607
Net Increase in Cash and Cash Equivalents	3,432	1,374
Cash and Cash Equivalents at End of Period	$ 10,098	$ 2,999

Operating Activities

Net Cash Flows from Operating Activities were $290 million in 2008. OPCo produced Net Income of $191 million during the period and a noncash expense item of $140 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. Accounts Payable had a $47 million inflow primarily due to increases in tonnage and prices per ton related to fuel and consumable purchases. Fuel, Materials and Supplies had a $41 million outflow due to price increases. Accounts Receivable, Net had a $38 million outflow primarily due to a coal contract amendment which reduced future deliveries in exchange for consideration received.

Net Cash Flows from Operating Activities were $279 million in 2007. OPCo produced income of $154 million during the period and a noncash expense item of $169 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The prior period activity in working capital relates to a number of items. Accounts Payable had a $47 million cash outflow partially due to emission allowance payments in January 2007. Accrued Taxes, Net, had a $47 million cash inflow primarily due to an increase of federal income tax related accruals offset by temporary timing differences of payments for property taxes. Fuel, Materials and Supplies had a $42 million cash outflow primarily due to an increase in coal inventory in preparation for the summer cooling season and an increase in materials related to projects at the Mitchell, Amos, Gavin and Sporn Plants.

Investing Activities

Net Cash Used for Investing Activities were $272 million and $560 million in 2008 and 2007, respectively. Construction Expenditures were $277 million and $566 million in 2008 and 2007, respectively, primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include the installation of selective catalytic reduction equipment and the flue gas desulfurization projects at the Cardinal, Amos and Mitchell Plants. In January 2007, environmental upgrades were completed for Unit 2 at the Mitchell Plant. For the remainder of 2008, OPCo expects construction expenditures to be approximately $410 million.

Financing Activities

Net Cash Flows Used for Financing Activities were $15 million in 2008. OPCo issued $165 million of Pollution Control Bonds and retired $250 million of Pollution Control Bonds. OPCo had a net increase in borrowings of $72 million from the Utility Money Pool.

Net Cash Flows from Financing Activities were $283 million in 2007. OPCo issued Senior Unsecured Notes for $400 million and $65 million of Pollution Control Bonds. OPCo had a net decrease in borrowings of $165 million from the Utility Money Pool.

Financing Activity

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

Issuances

Type of Debt		Principal Amount	Interest Rate	Due Date
		(in thousands)	**(%)**	
Pollution Control Bonds	$	50,000	Variable	2014
Pollution Control Bonds		50,000	Variable	2014
Pollution Control Bonds		65,000	Variable	2036

Retirements and Principal Payments

Type of Debt		Principal Amount Paid	Interest Rate	Due Date
		(in thousands)	**(%)**	
Notes Payable – Nonaffiliated	$	1,463	6.81	2008
Notes Payable – Nonaffiliated		6,000	6.27	2009
Pollution Control Bonds		50,000	Variable	2014
Pollution Control Bonds		50,000	Variable	2016
Pollution Control Bonds		50,000	Variable	2022
Pollution Control Bonds		35,000	Variable	2022
Pollution Control Bonds		65,000	Variable	2036

Liquidity

OPCo has solid investment grade ratings, which provide ready access to capital markets in order to issue new debt, refinance short-term debt or refinance long-term debt maturities. In addition, OPCo participates in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of contractual obligations is included in the 2007 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" and "Financing Activity" above and letters of credit. In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. As of June 30, 2008, $167 million of letters of credit were issued by OPCo under the 3-year credit agreement to support variable rate demand notes.

Significant Factors

Litigation and Regulatory Activity

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

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

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

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

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 183,037	$ 1,530	$ -	$ (10,714)	$ 173,853
Noncurrent Assets	93,550	254	-	(5,974)	87,830
Total MTM Derivative Contract Assets	276,587	1,784	-	(16,688)	261,683
Current Liabilities	(189,390)	(22,777)	(2,376)	17,082	(197,461)
Noncurrent Liabilities	(66,264)	(901)	(2,603)	4,305	(65,463)
Total MTM Derivative Contract Liabilities	(255,654)	(23,678)	(4,979)	21,387	(262,924)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,933	$ (21,894)	$ (4,979)	$ 4,699	$ (1,241)

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$	30,248
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(5,931)
Fair Value of New Contracts at Inception When Entered During the Period (a)		866
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(64)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		2,158
Changes in Fair Value Due to Market Fluctuations During the Period (c)		4,368
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		(10,712)
Total MTM Risk Management Contract Net Assets		20,933
Net Cash Flow & Fair Value Hedge Contracts		(21,894)
DETM Assignment (e)		(4,979)
Collateral Deposits		4,699
Ending Net Risk Management Assets at June 30, 2008	$	(1,241)

(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.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

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

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

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ (1,938)	$ 330	$ (14)	$ -	$ -	$ -	$ (1,622)
Level 2 (b)	(1,281)	13,609	8,184	3,604	1,247	-	25,363
Level 3 (c)	(6,774)	(1,096)	(2,719)	(1,752)	(904)	-	(13,245)
Total	(9,993)	12,843	5,451	1,852	343	-	10,496
Dedesignated Risk Management Contracts (d)	1,666	3,220	3,194	1,244	1,113	-	10,437
Total MTM Risk Management Contract Net Assets (Liabilities)	$ (8,327)	$ 16,063	$ 8,645	$ 3,096	$ 1,456	$ -	$ 20,933

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

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

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

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

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

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

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

	Power	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2007	$ (756)	$ 2,167	$ (254)	$ 1,157
Changes in Fair Value	(11,404)	(899)	205	(12,098)
Reclassifications from AOCI for Cash Flow Hedges Settled	101	(382)	(123)	(404)
Ending Balance in AOCI June 30, 2008	$ (12,059)	$ 886	$ (172)	$ (11,345)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $12.6 million loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

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

Six Months Ended June 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$585	$1,048	$385	$132	$325	$2,054	$490	$90

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

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which OPCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on OPCo's debt portfolio was $10.7 million.

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

	Three Months Ended		Six Months Ended	
	2008	**2007**	**2008**	**2007**
REVENUES				
Electric Generation, Transmission and Distribution	$ 515,884	$ 480,445	$ 1,071,362	$ 972,979
Sales to AEP Affiliates	256,399	180,205	493,247	359,099
Other - Affiliated	6,487	6,817	11,786	10,855
Other - Nonaffiliated	3,591	3,466	8,154	7,441
TOTAL	782,361	670,933	1,584,549	1,350,374
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	330,190	201,338	569,124	399,631
Purchased Electricity for Resale	39,155	27,868	73,732	52,722
Purchased Electricity from AEP Affiliates	35,157	28,745	67,673	49,711
Other Operation	91,959	86,972	181,841	189,959
Maintenance	59,218	50,617	107,915	109,765
Depreciation and Amortization	71,173	84,779	139,739	169,055
Taxes Other Than Income Taxes	45,937	50,320	97,515	98,705
TOTAL	672,789	530,639	1,237,539	1,069,548
OPERATING INCOME	109,572	140,294	347,010	280,826
Other Income (Expense):				
Interest Income	1,750	472	4,658	884
Carrying Costs Income	3,994	3,594	8,223	7,135
Allowance for Equity Funds Used During Construction	702	446	1,246	1,017
Interest Expense	(41,853)	(33,734)	(76,235)	(59,665)
INCOME BEFORE INCOME TAX EXPENSE	74,165	111,072	284,902	230,197
Income Tax Expense	21,271	36,732	94,181	76,596
NET INCOME	52,894	74,340	190,721	153,601
Preferred Stock Dividend Requirements	183	183	366	366
EARNINGS APPLICABLE TO COMMON STOCK	$ 52,711	$ 74,157	$ 190,355	$ 153,235

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

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

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 321,201	$ 536,639	$ 1,207,265	$ (56,763)	$ 2,008,342
FIN 48 Adoption, Net of Tax			(5,380)		(5,380)
Preferred Stock Dividends			(366)		(366)
TOTAL					2,002,596
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $523				971	971
NET INCOME			153,601		153,601
TOTAL COMPREHENSIVE INCOME					154,572
JUNE 30, 2007	$ 321,201	$ 536,639	$ 1,355,120	$ (55,792)	$ 2,157,168
DECEMBER 31, 2007	$ 321,201	$ 536,640	$ 1,469,717	$ (36,541)	$ 2,291,017
EITF 06-10 Adoption, Net of Tax of $1,004			(1,864)		(1,864)
SFAS 157 Adoption, Net of Tax of $152			(282)		(282)
Preferred Stock Dividends			(366)		(366)
TOTAL					2,288,505
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $6,732				(12,502)	(12,502)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $758				1,406	1,406
NET INCOME			190,721		190,721
TOTAL COMPREHENSIVE INCOME					179,625
JUNE 30, 2008	$ 321,201	$ 536,640	$ 1,657,926	$ (47,637)	$ 2,468,130

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

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 10,098	$ 6,666
Accounts Receivable:		
Customers	117,920	104,783
Affiliated Companies	125,613	119,560
Accrued Unbilled Revenues	26,903	26,819
Miscellaneous	20,689	1,578
Allowance for Uncollectible Accounts	(3,502)	(3,396)
Total Accounts Receivable	287,623	249,344
Fuel	125,844	92,874
Materials and Supplies	116,097	108,447
Risk Management Assets	173,853	44,236
Prepayments and Other	33,256	18,300
TOTAL	746,771	519,867
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	5,906,996	5,641,537
Transmission	1,092,630	1,068,387
Distribution	1,424,744	1,394,988
Other	371,427	318,805
Construction Work in Progress	586,892	716,640
Total	9,382,689	9,140,357
Accumulated Depreciation and Amortization	3,032,379	2,967,285
TOTAL - NET	6,350,310	6,173,072
OTHER NONCURRENT ASSETS		
Regulatory Assets	327,764	323,105
Long-term Risk Management Assets	87,830	49,586
Deferred Charges and Other	230,925	272,799
TOTAL	646,519	645,490
TOTAL ASSETS	$ 7,743,600	$ 7,338,429

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

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

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 173,833	$ 101,548
Accounts Payable:		
General	209,084	141,196
Affiliated Companies	104,468	137,389
Short-term Debt – Nonaffiliated	-	701
Long-term Debt Due Within One Year – Nonaffiliated	125,225	55,188
Risk Management Liabilities	197,461	40,548
Customer Deposits	32,031	30,613
Accrued Taxes	180,760	185,011
Accrued Interest	39,687	41,880
Other	143,465	149,658
TOTAL	1,206,014	883,732
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,432,266	2,594,410
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	65,463	32,194
Deferred Income Taxes	926,957	914,170
Regulatory Liabilities and Deferred Investment Tax Credits	154,258	160,721
Deferred Credits and Other	256,438	229,635
TOTAL	4,035,382	4,131,130
TOTAL LIABILITIES	5,241,396	5,014,862
Minority Interest	17,447	15,923
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,627	16,627
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	536,640	536,640
Retained Earnings	1,657,926	1,469,717
Accumulated Other Comprehensive Income (Loss)	(47,637)	(36,541)
TOTAL	2,468,130	2,291,017
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,743,600	$ 7,338,429

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

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

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 190,721	$ 153,601
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	139,739	169,055
Deferred Income Taxes	27,984	550
Carrying Costs Income	(8,223)	(7,135)
Allowance for Equity Funds Used During Construction	(1,246)	(1,017)
Mark-to-Market of Risk Management Contracts	2,018	2,876
Deferred Property Taxes	42,089	34,629
Change in Other Noncurrent Assets	(59,294)	(17,321)
Change in Other Noncurrent Liabilities	13,265	272
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(38,279)	(18,273)
Fuel, Materials and Supplies	(40,620)	(42,452)
Accounts Payable	47,035	(46,758)
Accrued Taxes, Net	(5,865)	46,587
Other Current Assets	(9,620)	162
Other Current Liabilities	(9,760)	4,253
Net Cash Flows from Operating Activities	289,944	279,029
INVESTING ACTIVITIES		
Construction Expenditures	(276,911)	(565,832)
Proceeds from Sales of Assets	5,889	5,594
Other	(505)	(24)
Net Cash Flows Used for Investing Activities	(271,527)	(560,262)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	164,474	461,324
Change in Short-term Debt, Net – Nonaffiliated	(701)	(1,203)
Change in Advances from Affiliates, Net	72,285	(164,698)
Retirement of Long-term Debt – Nonaffiliated	(257,463)	(8,927)
Retirement of Cumulative Preferred Stock	-	(2)
Principal Payments for Capital Lease Obligations	(3,214)	(3,521)
Dividends Paid on Cumulative Preferred Stock	(366)	(366)
Other	10,000	-
Net Cash Flows from (Used for) Financing Activities	(14,985)	282,607
Net Increase in Cash and Cash Equivalents	3,432	1,374
Cash and Cash Equivalents at Beginning of Period	6,666	1,625
Cash and Cash Equivalents at End of Period	$ 10,098	$ 2,999
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 72,685	$ 51,991
Net Cash Paid (Received) for Income Taxes	32,569	(9,193)
Noncash Acquisitions Under Capital Leases	1,673	1,036
Construction Expenditures Included in Accounts Payable at June 30,	27,610	65,936

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

Results of Operations

Second Quarter of 2008 Compared to Second Quarter of 2007

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

Second Quarter of 2007		$ 6
Changes in Gross Margin:		
Retail and Off-system Sales Margins	8	
Transmission Revenues	3	
Other	1	
Total Change in Gross Margin		12
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(6)	
Deferral of Ice Storm Costs	(8)	
Depreciation and Amortization	(2)	
Other Income	3	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(15)
Income Tax Expense		1
Second Quarter of 2008		$ 4

Net Income decreased $2 million to $4 million in 2008. The key drivers of the decrease were a $15 million increase in Operating Expenses and Other offset by a $12 million increase in Gross Margin and a $1 million decrease in Income Tax Expense.

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

- Retail and Off-system Sales Margins increased $8 million primarily due to:
  - A $7 million increase in retail sales margins mainly due to base rate adjustments and a slight increase in KWH sales.
  - A $1 million net increase in off-system margins retained primarily due to higher physical sales margins, partially offset by lower trading margins.
- Transmission Revenues increased $3 million primarily due to higher rates within SPP.

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

- Other Operation and Maintenance expenses increased $6 million primarily due to:
  - A $7 million increase due to a credit in 2007 to adjust the expenses of the January 2007 ice storm.
  - A $4 million increase in transmission expense primarily due to an increase in transmission services from other utilities.
  - A $3 million increase in administrative and general expenses, primarily associated with maintenance, outside services and employee-related expenses.
  - A $2 million increase in expense for the June 2008 storms.
  - A $2 million increase due to amortization of the deferred ice storm costs.

  These increases were partially offset by:
  - A $10 million decrease primarily to true-up actual December ice storm costs to the 2007 estimated accrual and is offset in the Deferral below. See "Deferral of Ice Storm Costs" below.
- Deferral of Ice Storm Costs increased $8 million due to 2008 costs and true-up entries as discussed above. See "Oklahoma 2007 Ice Storms" section of Note 3.
- Depreciation and Amortization expenses increased $2 million primarily due to a $3 million increase in the amortization of the Lawton Settlement regulatory asset offset by a $1 million decrease in depreciation primarily resulting from lower rates.
- Other Income increased $3 million primarily due to an increase in carrying charges related to the new peaking units and to deferred ice storms costs. See "Oklahoma 2007 Ice Storms" section of Note 3.
- Interest Expense increased $2 million primarily due to a $4 million increase in interest expense from long-term borrowings offset by a $1 million decrease in interest expense from short-term borrowings.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Reconciliation of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2008
Net Income (Loss)
(in millions)

Six Months Ended June 30, 2007		$ (14)
Changes in Gross Margin:		
Retail and Off-system Sales Margins	22	
Transmission Revenues	4	
Other	11	
Total Change in Gross Margin		37
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(13)	
Deferral of Ice Storm Costs	72	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	(1)	
Other Income	6	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		54
Income Tax Expense		(35)
Six Months Ended June 30, 2008		$ 42

Net Income (Loss) increased $56 million to $42 million in 2008. The key drivers of the increase were a $54 million decrease in Operating Expenses and Other and a $37 million increase in Gross Margin offset by a $35 million increase in Income Tax Expense.

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

- Retail and Off-system Sales Margins increased $22 million primarily due to an increase in retail sales margins resulting from base rate adjustments and a slight increase in KWH sales.
- Transmission Revenues increased $4 million primarily due to higher rates within SPP.
- Other revenues increased $11 million primarily due to a $10 million increase related to the recognition of the sale of SO_2 allowances. See "Oklahoma 2007 Ice Storms" section of Note 3.

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

- Other Operation and Maintenance expenses increased $13 million primarily due to:
  - A $10 million increase in production expenses primarily due to a write-off of pre-construction costs related to the canceled Red Rock Generating Facility. See "Red Rock Generating Facility" section of Note 3.
  - A $9 million increase due to amortization of the deferred 2007 ice storm costs.
  - An $8 million increase in transmission expense primarily due to an increase in transmission services from other utilities.
  - A $4 million increase in administrative and general expenses, primarily associated with maintenance, outside services and employee-related expenses.
  - A $2 million increase in expense for the June 2008 storms.
  - A $1 million increase in distribution maintenance expense due to increased vegetation management activities.

  These increases were partially offset by:
  - A $14 million decrease for the costs of the January 2007 ice storm.
  - A $10 million decrease primarily to true-up actual December ice storm costs to the 2007 estimated accrual.
- Deferral of Ice Storm Costs in 2008 of $72 million results from an OCC order approving recovery of ice storm costs related to ice storms in January and December 2007. See "Oklahoma 2007 Ice Storms" section of Note 3.
- Depreciation and Amortization expenses increased $5 million primarily due to a $7 million increase related to the amortization of the Lawton Settlement regulatory asset offset by a $2 million decrease in depreciation primarily resulting from lower rates.
- Other Income increased $6 million primarily due to a $3 million increase in carrying charges related to the new peaking units and to deferred ice storms costs (see "Oklahoma 2007 Ice Storms" section of Note 3) and a $1 million increase in the equity component of AFUDC.
- Interest Expense increased $5 million primarily due to an $8 million increase in interest expense from long-term borrowings offset by a $2 million decrease in interest expense from short-term borrowings.
- Income Tax Expense increased $35 million primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

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

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

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

Cash Flow

Cash flows for the six months ended June 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,370	$ 1,651
Cash Flows from (Used for):		
Operating Activities	(6,309)	(30,543)
Investing Activities	(99,942)	(161,760)
Financing Activities	106,405	191,560
Net Increase (Decrease) in Cash and Cash Equivalents	154	(743)
Cash and Cash Equivalents at End of Period	$ 1,524	$ 908

Operating Activities

Net Cash Flows Used for Operating Activities were $6 million in 2008. PSO produced Net Income of $42 million during the period and had noncash expense items of $71 million for Deferred Income Taxes and $51 million for Depreciation and Amortization. PSO established a $72 million regulatory asset for an OCC order approving recovery of ice storm costs related to storms in January and December 2007. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital primarily relates to Fuel Over/Under-Recovery, Net which had a $74 million outflow as a result of rapidly increasing cost of natural gas which fuels the majority of PSO's generators.

Net Cash Flows Used for Operating Activities were $31 million in 2007. PSO incurred a Net Loss of $14 million during the period and had a noncash expense item of $46 million for Depreciation and Amortization. The $26 million outflow from Other Noncurrent Assets was primarily related to the establishment of a $35 million regulatory asset for the payment of the Lawton Settlement. The other changes in assets and liabilities represent items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $14 million outflow from Fuel Over/Under-Recovery, Net was the result of increasing costs of natural gas which fuels the majority of PSO's generators. The $22 million outflow from Other Current Liabilities was primarily due to $18 million fewer outstanding checks at June 30, 2007 when compared to December 31, 2006.

Investing Activities

Net Cash Flows Used for Investing Activities during 2008 and 2007 were $100 million and $162 million, respectively. Construction Expenditures of $152 million in 2008 and 2007 were primarily related to projects for improved generation, transmission and distribution service reliability. In addition, during 2008, PSO had a net decrease of $51 million in loans to the Utility Money Pool. For the remainder of 2008, PSO expects construction expenditures to be approximately $130 million.

Financing Activities

Net Cash Flows from Financing Activities were $106 million during 2008. PSO had a net increase of $111 million in borrowings from the Utility Money Pool. PSO repurchased $34 million in Pollution Control Bonds in May 2008. PSO received a capital contribution from Parent of $30 million.

Net Cash Flows from Financing Activities were $192 million during 2007. PSO had a net increase of $140 million in borrowings from the Utility Money Pool. PSO received a capital contribution from Parent of $40 million.

Financing Activity

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

<u>Issuances</u>

None

Retirements and Principal Payments

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

Liquidity

PSO has solid investment grade ratings, which provide ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, PSO participates in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

PSO's contractual obligations include amounts reported on PSO's Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes PSO's contractual cash obligations at December 31, 2007:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Interest on Fixed Rate Portion of Long-term Debt (a)	$ 51.7	$ 99.5	$ 78.5	$ 695.2	$ 924.9
Fixed Rate Portion of Long-term Debt (b)	-	200.0	75.0	612.7	887.7
Variable Rate Portion of Long-term Debt (c)	-	-	-	33.7	33.7
Capital Lease Obligations (d)	1.7	2.2	0.5	-	4.4
Noncancelable Operating Leases (d)	6.7	10.7	5.7	5.6	28.7
Fuel Purchase Contracts (e)	295.6	130.1	85.3	-	511.0
Energy and Capacity Purchase Contracts (f)	6.9	6.4	-	-	13.3
Construction Contracts for Capital Assets (g)	55.2	128.4	143.5	10.0	337.1
Total	$ 417.8	$ 577.3	$ 388.5	$ 1,357.2	$ 2,740.8

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2007 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) See Note 15 of the 2007 Annual Report. Represents principal only excluding interest.
(c) See Note 15 of the 2007 Annual Report. Represents principal only excluding interest. Variable rate debt had a 3.75% interest rate at December 31, 2007.
(d) See Note 14 of the 2007 Annual Report.
(e) Represents contractual obligations to purchase coal, natural gas and other consumable as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

PSO's FIN 48 liabilities of $5 million are not included above because PSO cannot reasonably estimate the cash flows by period.

As discussed in Note 9 of the 2007 Annual Report, PSO's minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trusts.

As of December 31, 2007, PSO had no outstanding standby letters of credit or guarantees of performance.

The summary of contractual obligations has not changed significantly from year-end other than the debt retirement discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

Litigation and Regulatory Activity

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

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

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

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

	MTM Risk Management Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 88,788	$ -	$ (1,705)	$ 87,083
Noncurrent Assets	12,321	-	(39)	12,282
Total MTM Derivative Contract Assets	101,109	-	(1,744)	99,365
Current Liabilities	(86,621)	(93)	2,249	(84,465)
Noncurrent Liabilities	(11,098)	(102)	852	(10,348)
Total MTM Derivative Contract Liabilities	(97,719)	(195)	3,101	(94,813)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,390	$ (195)	$ 1,357	$ 4,552

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$	6,981
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(4,066)
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		32
Changes in Fair Value Due to Market Fluctuations During the Period (c)		(146)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		589
Total MTM Risk Management Contract Net Assets		3,390
DETM Assignment (e)		(195)
Collateral Deposits		1,357
Ending Net Risk Management Assets at June 30, 2008	$	4,552

(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.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

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

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

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ 1,167	$ (235)	$ -	$ -	$ -	$ -	$ 932
Level 2 (b)	434	2,189	(128)	(14)	-	-	2,481
Level 3 (c)	(24)	-	1	-	-	-	(23)
Total	$ 1,577	$ 1,954	$ (127)	$ (14)	$ -	$ -	$ 3,390

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

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

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

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

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

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

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

	Interest Rate
Beginning Balance in AOCI December 31, 2007	$ (887)
Changes in Fair Value	-
Reclassifications from AOCI for Cash Flow Hedges Settled	91
Ending Balance in AOCI June 30, 2008	$ (796)

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

Credit Risk

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

VaR Associated with Risk Management Contracts

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

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

Six Months Ended June 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$39	$109	$37	$8	$13	$189	$53	$5

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

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which PSO's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on PSO's debt portfolio was $800 thousand.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Six Months Ended 2008	Six Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 357,675	$ 304,820	$ 676,555	$ 594,900
Sales to AEP Affiliates	41,767	16,275	57,702	40,868
Other	892	544	2,077	1,184
TOTAL	400,334	321,639	736,334	636,952
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	143,537	113,633	296,742	256,148
Purchased Electricity for Resale	104,016	70,145	152,598	137,554
Purchased Electricity from AEP Affiliates	21,506	18,979	38,775	32,463
Other Operation	45,186	42,345	101,185	83,352
Maintenance	25,655	22,177	60,242	65,262
Deferral of Ice Storm Costs	8,223	-	(71,679)	-
Depreciation and Amortization	24,720	22,992	50,887	45,698
Taxes Other Than Income Taxes	10,474	9,890	21,426	20,184
TOTAL	383,317	300,161	650,176	640,661
OPERATING INCOME (LOSS)	17,017	21,478	86,158	(3,709)
Other Income (Expense):				
Interest Income	967	518	2,095	518
Carrying Costs Income	2,128	-	3,762	-
Allowance for Equity Funds Used During Construction	516	44	1,875	690
Interest Expense	(14,525)	(12,785)	(29,466)	(24,168)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT)	6,103	9,255	64,424	(26,669)
Income Tax Expense (Credit)	1,976	2,960	22,898	(12,538)
NET INCOME (LOSS)	4,127	6,295	41,526	(14,131)
Preferred Stock Dividend Requirements	53	53	106	106
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 4,074	$ 6,242	$ 41,420	$ (14,237)

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 Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 157,230	$ 230,016	$ 199,262	$ (1,070)	$ 585,438
FIN 48 Adoption, Net of Tax			(386)		(386)
Capital Contribution from Parent		40,000			40,000
Preferred Stock Dividends			(106)		(106)
TOTAL					624,946
COMPREHENSIVE LOSS					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $49				91	91
NET LOSS			(14,131)		(14,131)
TOTAL COMPREHENSIVE LOSS					(14,040)
JUNE 30, 2007	$ 157,230	$ 270,016	$ 184,639	$ (979)	$ 610,906
DECEMBER 31, 2007	$ 157,230	$ 310,016	$ 174,539	$ (887)	$ 640,898
EITF 06-10 Adoption, Net of Tax of $596			(1,107)		(1,107)
Capital Contribution from Parent		30,000			30,000
Preferred Stock Dividends			(106)		(106)
TOTAL					669,685
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $49				91	91
NET INCOME			41,526		41,526
TOTAL COMPREHENSIVE INCOME					41,617
JUNE 30, 2008	$ 157,230	$ 340,016	$ 214,852	$ (796)	$ 711,302

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

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,524	$ 1,370
Advances to Affiliates	-	51,202
Accounts Receivable:		
Customers	54,815	74,330
Affiliated Companies	79,370	59,835
Miscellaneous	10,748	10,315
Allowance for Uncollectible Accounts	(18)	-
Total Accounts Receivable	144,915	144,480
Fuel	27,124	19,394
Materials and Supplies	47,925	47,691
Risk Management Assets	87,083	33,308
Accrued Tax Benefits	52,082	31,756
Regulatory Asset for Under-Recovered Fuel Costs	61,876	-
Margin Deposits	992	8,980
Prepayments and Other	14,559	18,137
TOTAL	438,080	356,318
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,234,217	1,110,657
Transmission	598,361	569,746
Distribution	1,402,521	1,337,038
Other	249,073	241,722
Construction Work in Progress	94,615	200,018
Total	3,578,787	3,459,181
Accumulated Depreciation and Amortization	1,191,109	1,182,171
TOTAL - NET	2,387,678	2,277,010
OTHER NONCURRENT ASSETS		
Regulatory Assets	186,807	158,731
Long-term Risk Management Assets	12,282	3,358
Deferred Charges and Other	67,944	48,454
TOTAL	267,033	210,543
TOTAL ASSETS	$ 3,092,791	$ 2,843,871

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

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

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 110,981	$ -
Accounts Payable:		
General	164,652	189,032
Affiliated Companies	107,254	80,316
Long-term Debt Due Within One Year – Nonaffiliated	50,000	-
Risk Management Liabilities	84,465	27,118
Customer Deposits	40,409	41,477
Accrued Taxes	36,383	18,374
Regulatory Liability for Over-Recovered Fuel Costs	-	11,697
Other	42,588	57,708
TOTAL	636,732	425,722
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	834,737	918,316
Long-term Risk Management Liabilities	10,348	2,808
Deferred Income Taxes	526,319	456,497
Regulatory Liabilities and Deferred Investment Tax Credits	316,575	338,788
Deferred Credits and Other	51,516	55,580
TOTAL	1,739,495	1,771,989
TOTAL LIABILITIES	2,376,227	2,197,711
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $15 Par Value Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	340,016	310,016
Retained Earnings	214,852	174,539
Accumulated Other Comprehensive Income (Loss)	(796)	(887)
TOTAL	711,302	640,898
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,092,791	$ 2,843,871

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

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

	2008	2007
OPERATING ACTIVITIES		
Net Income (Loss)	$ 41,526	$ (14,131)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows Used for Operating Activities:		
Depreciation and Amortization	50,887	45,698
Deferred Income Taxes	70,618	11,059
Deferral of Ice Storm Costs	(71,679)	-
Allowance for Equity Funds Used During Construction	(1,875)	(690)
Mark-to-Market of Risk Management Contracts	2,216	4,832
Deferred Property Taxes	(17,796)	(16,539)
Change in Other Noncurrent Assets	25,981	(25,601)
Change in Other Noncurrent Liabilities	(33,384)	(22,811)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	1,270	19,413
Fuel, Materials and Supplies	(7,964)	(8,414)
Margin Deposits	7,988	10,216
Accounts Payable	18,238	11,810
Customer Deposits	(1,068)	(3,354)
Accrued Taxes, Net	(2,317)	(6,888)
Fuel Over/Under-Recovery, Net	(73,573)	(13,512)
Other Current Assets	820	597
Other Current Liabilities	(16,197)	(22,228)
Net Cash Flows Used for Operating Activities	(6,309)	(30,543)
INVESTING ACTIVITIES		
Construction Expenditures	(151,711)	(151,973)
Change in Other Cash Deposits, Net	-	(12,896)
Change in Advances to Affiliates, Net	51,202	-
Proceeds from Sales of Assets	567	3,109
Net Cash Flows Used for Investing Activities	(99,942)	(161,760)
FINANCING ACTIVITIES		
Capital Contribution from Parent	30,000	40,000
Issuance of Long-term Debt – Nonaffiliated	-	12,495
Change in Advances from Affiliates, Net	110,981	139,916
Retirement of Long-term Debt – Nonaffiliated	(33,700)	-
Principal Payments for Capital Lease Obligations	(770)	(745)
Dividends Paid on Cumulative Preferred Stock	(106)	(106)
Net Cash Flows from Financing Activities	106,405	191,560
Net Increase (Decrease) in Cash and Cash Equivalents	154	(743)
Cash and Cash Equivalents at Beginning of Period	1,370	1,651
Cash and Cash Equivalents at End of Period	$ 1,524	$ 908
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 27,774	$ 21,339
Net Cash Received for Income Taxes	19,529	2,353
Noncash Acquisitions Under Capital Leases	253	434
Construction Expenditures Included in Accounts Payable at June 30,	11,731	21,261

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

Second Quarter of 2008 Compared to Second Quarter of 2007

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

Second Quarter of 2007		$ 2
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	23	
Transmission Revenues	2	
Other	(2)	
Total Change in Gross Margin		23
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(7)	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	2	
Other Income	1	
Total Change in Operating Expenses and Other		(6)
Income Tax Expense		(5)
Second Quarter of 2008		$ 14

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

Net Income increased $12 million to $14 million in 2008. The key drivers of the increase were a $23 million increase in Gross Margin partially offset by a $6 million increase in Operating Expenses and Other and a $5 million increase in Income Tax Expense.

The major component 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 $23 million primarily due to a $25 million refund provision booked in 2007 pursuant to an unfavorable ALJ ruling in the Texas Fuel Reconciliation proceeding.
- Transmission Revenues increased $2 million due to higher rates in the SPP region.
- Other revenues decreased $2 million primarily due to a $6 million decrease in gains on sales of emission allowances offset by a $4 million increase in revenues from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to Cleco Corporation, a nonaffiliated entity. The increase in coal deliveries was the result of planned and forced outages during 2007 at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation. The increased revenue from coal deliveries was offset by a corresponding increase in Other Operation and Maintenance expenses from mining operations as discussed below.

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

- Other Operation and Maintenance expenses increased $7 million primarily due to a $5 million increase in expenses for coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC. The increased expenses for coal deliveries were partially offset by a corresponding increase in revenues from mining operations as discussed above.
- Depreciation and Amortization increased $2 million primarily due to higher depreciable asset balances.
- Taxes Other Than Income Taxes decreased $2 million primarily due to a decrease in franchise taxes.
- Income Tax Expense increased $5 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Reconciliation of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2008
Net Income
(in millions)

Six Months Ended June 30, 2007		$ 11
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	28	
Transmission Revenues	3	
Other	(3)	
Total Change in Gross Margin		28
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(17)	
Depreciation and Amortization	(4)	
Other Income	3	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(20)
Six Months Ended June 30, 2008		$ 19

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

Net Income increased $8 million to $19 million in 2008. The key drivers of the increase were a $28 million increase in Gross Margin partially offset by a $20 million increase in Operating Expenses and Other.

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

- Retail and Off-system Sales Margins increased $28 million primarily due to a $25 million refund provision booked in 2007 pursuant to an unfavorable ALJ ruling in the Texas Fuel Reconciliation proceeding.
- Transmission Revenues increased $3 million due to higher rates in the SPP region.
- Other revenues decreased $3 million primarily due to a $12 million decrease in gains on sales of emission allowances offset by a $9 million increase in revenue from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to Cleco Corporation, a nonaffiliated entity. The increase in coal deliveries was the result of planned and forced outages during 2007 at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation. The increased revenue from coal deliveries was offset by a corresponding increase in Other Operation and Maintenance expenses from mining operations as discussed below.

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

- Other Operation and Maintenance expenses increased $17 million primarily due to the following:
  - An $11 million increase in expenses for coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC. The increased expenses for coal deliveries were partially offset by a corresponding increase in revenues from mining operations as discussed above.
  - A $3 million increase in transmission expenses related to increased usage and rates in the SPP region.
  - A $3 million increase in administrative and general expenses, primarily associated with outside services and employee-related expenses.
- Depreciation and Amortization increased $4 million primarily due to higher depreciable asset balances.
- Other Income increased $3 million primarily due to an increase in the equity component of AFUDC as a result of new generation projects.
- Interest Expense increased $2 million primarily due to higher interest of $8 million related to higher long-term debt partially offset by a $4 million increase in the debt component of AFUDC due to new generation projects and a $3 million decrease in other interest expense partially related to decreased interest expense on fuel recovery.

Financial Condition

Credit Ratings

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

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

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

Cash Flow

Cash flows for the six months ended June 30, 2008 and 2007 were as follows:

	2008	2007
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,742	$ 2,618
Cash Flows from (Used for):		
Operating Activities	74,622	120,597
Investing Activities	(569,109)	(253,267)
Financing Activities	494,987	131,610
Net Increase (Decrease) in Cash and Cash Equivalents	500	(1,060)
Cash and Cash Equivalents at End of Period	$ 2,242	$ 1,558

Operating Activities

Net Cash Flows from Operating Activities were $75 million in 2008. SWEPCo produced Net Income of $19 million during the period and had a noncash expense item of $73 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 $84 million outflow from Fuel Over/Under-Recovery, Net was the result of higher fuel costs. The $61 million inflow from Accounts Payable was primarily due to higher fuel related costs. The $32 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $13 million outflow from Accrued Taxes, Net was the result of increased payments related to property and income taxes.

Net Cash Flows from Operating Activities were $121 million in 2007. SWEPCo produced Net Income of $11 million during the period and had noncash expense items of $69 million for Depreciation and Amortization and $25 million related to the Provision for Fuel Disallowance recorded as the result of an ALJ ruling in SWEPCo's Texas fuel reconciliation proceeding. The other changes in assets and liabilities represent items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $36 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes. The $27 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company.

Investing Activities

Cash Flows Used for Investing Activities during 2008 and 2007 were $569 million and $253 million, respectively. Construction Expenditures of $266 million and $250 million in 2008 and 2007, respectively, were primarily related to new generation projects at the Turk Plant, Mattison Plant and Stall Unit. In addition, during 2008, SWEPCo had a net increase of $301 million in loans to the Utility Money Pool. For the remainder of 2008, SWEPCo expects construction expenditures to be approximately $350 million.

Financing Activities

Cash Flows from Financing Activities were $495 million during 2008. SWEPCo issued $400 million of Senior Unsecured Notes. SWEPCo received a capital contribution from Parent of $100 million.

Cash Flows from Financing Activities were $132 million during 2007. SWEPCo issued $250 million of Senior Unsecured Notes and had a net decrease of $135 million in borrowings from the Utility Money Pool. SWEPCo received a capital contribution from Parent of $25 million.

Financing Activity

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

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$ 400,000	6.45	2019

Retirements and Principal Payments

Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Nonaffiliated	$ 2,203	4.47	2011
Notes Payable – Nonaffiliated	1,500	Variable	2008

Liquidity

SWEPCo has solid investment grade ratings, which provide ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, SWEPCo participates in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of contractual obligations is included in the 2007 Annual Report and has not changed significantly from year-end other than the debt issuance discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

Litigation and Regulatory Activity

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

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

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

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

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 108,564	$ -	$ -	$ (2,014)	$ 106,550
Noncurrent Assets	15,872	71	-	(46)	15,897
Total MTM Derivative Contract Assets	124,436	71	-	(2,060)	122,447
Current Liabilities	(106,167)	(4)	(110)	3,144	(103,137)
Noncurrent Liabilities	(14,030)	-	(120)	1,252	(12,898)
Total MTM Derivative Contract Liabilities	(120,197)	(4)	(230)	4,396	(116,035)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,239	$ 67	$ (230)	$ 2,336	$ 6,412

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007	$ 8,131
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(4,779)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	418
Changes in Fair Value Due to Market Fluctuations During the Period (c)	(258)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	727
Total MTM Risk Management Contract Net Assets	4,239
Net Cash Flow & Fair Value Hedge Contracts	67
DETM Assignment (e)	(230)
Collateral Deposits	2,336
Ending Net Risk Management Assets at June 30, 2008	$ 6,412

(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.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 16 of the 2007 Annual Report.

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

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

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

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ 1,376	$ (277)	$ -	$ -	$ -	$ -	$ 1,099
Level 2 (b)	366	3,072	(237)	(16)	-	-	3,185
Level 3 (c)	(47)	-	2	-	-	-	(45)
Total	$ 1,695	$ 2,795	$ (235)	$ (16)	$ -	$ -	$ 4,239

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

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

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

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

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

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

	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2007	$ (6,650)	$ 629	$ (6,021)
Changes in Fair Value	-	120	120
Reclassifications from AOCI for Cash Flow Hedges Settled	413	(705)	(292)
Ending Balance in AOCI June 30, 2008	$ (6,237)	$ 44	$ (6,193)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $829 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

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

Six Months Ended June 30, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$62	$163	$54	$11	$17	$245	$75	$7

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

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which SWEPCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on SWEPCo's debt portfolio was $2 million.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Six Months Ended 2008	Six Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 405,632	$ 329,250	$ 731,533	$ 656,534
Sales to AEP Affiliates	17,592	16,237	31,184	32,652
Other	393	535	693	935
TOTAL	423,617	346,022	763,410	690,121
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	147,147	125,994	264,808	237,981
Purchased Electricity for Resale	54,378	56,870	94,648	109,368
Purchased Electricity from AEP Affiliates	51,932	16,085	72,372	39,002
Other Operation	58,757	50,204	122,336	103,987
Maintenance	27,692	29,721	55,160	56,060
Depreciation and Amortization	36,897	34,668	73,033	68,790
Taxes Other Than Income Taxes	15,705	17,540	33,124	33,531
TOTAL	392,508	331,082	715,481	648,719
OPERATING INCOME	31,109	14,940	47,929	41,402
Other Income (Expense):				
Interest Income	1,540	776	2,417	1,481
Allowance for Equity Funds Used During Construction	2,952	2,562	6,015	3,953
Interest Expense	(17,270)	(17,235)	(34,412)	(32,725)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT) AND MINORITY INTEREST EXPENSE	18,331	1,043	21,949	14,111
Income Tax Expense (Credit)	3,351	(1,553)	1,364	1,068
Minority Interest Expense	899	972	1,894	1,814
NET INCOME	14,081	1,624	18,691	11,229
Preferred Stock Dividend Requirements	57	57	114	114
EARNINGS APPLICABLE TO COMMON STOCK	$ 14,024	$ 1,567	$ 18,577	$ 11,115

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

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

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 135,660	$ 245,003	$ 459,338	$ (18,799)	$ 821,202
FIN 48 Adoption, Net of Tax			(1,642)		(1,642)
Capital Contribution from Parent		25,000			25,000
Preferred Stock Dividends			(114)		(114)
TOTAL					844,446
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $172				(79)	(79)
NET INCOME			11,229		11,229
TOTAL COMPREHENSIVE INCOME					11,150
JUNE 30, 2007	$ 135,660	$ 270,003	$ 468,811	$ (18,878)	$ 855,596
DECEMBER 31, 2007	$ 135,660	$ 330,003	$ 523,731	$ (16,439)	$ 972,955
EITF 06-10 Adoption, Net of Tax of $622			(1,156)		(1,156)
SFAS 157 Adoption, Net of Tax of $6			10		10
Capital Contribution from Parent		100,000			100,000
Preferred Stock Dividends			(114)		(114)
TOTAL					1,071,695
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $92				(172)	(172)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $253				471	471
NET INCOME			18,691		18,691
TOTAL COMPREHENSIVE INCOME					18,990
JUNE 30, 2008	$ 135,660	$ 430,003	$ 541,162	$ (16,140)	$ 1,090,685

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
June 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,242	$ 1,742
Advances to Affiliates	300,525	-
Accounts Receivable:		
Customers	64,754	91,379
Affiliated Companies	25,663	33,196
Miscellaneous	12,723	10,544
Allowance for Uncollectible Accounts	(139)	(143)
Total Accounts Receivable	103,001	134,976
Fuel	87,705	75,662
Materials and Supplies	51,581	48,673
Risk Management Assets	106,550	39,850
Regulatory Asset for Under-Recovered Fuel Costs	67,186	5,859
Margin Deposits	1,319	10,650
Prepayments and Other	70,233	28,147
TOTAL	790,342	345,559
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,751,081	1,743,198
Transmission	770,560	737,975
Distribution	1,351,982	1,312,746
Other	642,255	631,765
Construction Work in Progress	632,514	451,228
Total	5,148,392	4,876,912
Accumulated Depreciation and Amortization	1,964,954	1,939,044
TOTAL - NET	3,183,438	2,937,868
OTHER NONCURRENT ASSETS		
Regulatory Assets	118,139	133,617
Long-term Risk Management Assets	15,897	4,073
Deferred Charges and Other	107,440	67,269
TOTAL	241,476	204,959
TOTAL ASSETS	$ 4,215,256	$ 3,488,386

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

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

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 1,565
Accounts Payable:		
General	183,533	152,305
Affiliated Companies	89,863	51,767
Short-term Debt – Nonaffiliated	7,039	285
Long-term Debt Due Within One Year – Nonaffiliated	4,406	5,906
Risk Management Liabilities	103,137	32,629
Customer Deposits	36,729	37,473
Accrued Taxes	49,529	26,494
Regulatory Liability for Over-Recovered Fuel Costs	-	22,879
Other	91,895	76,554
TOTAL	566,131	407,857
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,538,795	1,141,311
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	12,898	3,334
Deferred Income Taxes	397,158	361,806
Regulatory Liabilities and Deferred Investment Tax Credits	340,563	334,014
Deferred Credits and Other	212,656	210,725
TOTAL	2,552,070	2,101,190
TOTAL LIABILITIES	3,118,201	2,509,047
Minority Interest	1,673	1,687
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,697
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	430,003	330,003
Retained Earnings	541,162	523,731
Accumulated Other Comprehensive Income (Loss)	(16,140)	(16,439)
TOTAL	1,090,685	972,955
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,215,256	$ 3,488,386

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 18,691	$ 11,229
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	73,033	68,790
Deferred Income Taxes	28,256	(21,658)
Provision for Fuel Disallowance	-	24,500
Allowance for Equity Funds Used During Construction	(6,015)	(3,953)
Mark-to-Market of Risk Management Contracts	1,541	5,190
Deferred Property Taxes	(19,866)	(19,210)
Change in Other Noncurrent Assets	3,434	3,846
Change in Other Noncurrent Liabilities	(17,106)	(7,932)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	31,975	26,897
Fuel, Materials and Supplies	(14,978)	(11,126)
Accounts Payable	60,552	8,388
Accrued Taxes, Net	(12,503)	36,445
Fuel Over/Under-Recovery, Net	(84,206)	1,293
Other Current Assets	7,296	12,928
Other Current Liabilities	4,518	(15,030)
Net Cash Flows from Operating Activities	74,622	120,597
INVESTING ACTIVITIES		
Construction Expenditures	(266,145)	(250,409)
Change in Advances to Affiliates, Net	(300,525)	-
Other	(2,439)	(2,858)
Net Cash Flows Used for Investing Activities	(569,109)	(253,267)
FINANCING ACTIVITIES		
Capital Contribution from Parent	100,000	25,000
Issuance of Long-term Debt – Nonaffiliated	396,446	247,496
Change in Short-term Debt, Net – Nonaffiliated	6,754	5,230
Change in Advances from Affiliates, Net	(1,565)	(135,010)
Retirement of Long-term Debt – Nonaffiliated	(3,703)	(8,609)
Principal Payments for Capital Lease Obligations	(2,831)	(2,383)
Dividends Paid on Cumulative Preferred Stock	(114)	(114)
Net Cash Flows from Financing Activities	494,987	131,610
Net Increase (Decrease) in Cash and Cash Equivalents	500	(1,060)
Cash and Cash Equivalents at Beginning of Period	1,742	2,618
Cash and Cash Equivalents at End of Period	$ 2,242	$ 1,558
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 19,848	$ 25,876
Net Cash Paid for Income Taxes	10,276	10,617
Noncash Acquisitions Under Capital Leases	17,236	6,511
Construction Expenditures Included in Accounts Payable at June 30,	68,670	38,630

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

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

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

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Significant Accounting Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
2.	New Accounting Pronouncements and Extraordinary Item	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
3.	Rate Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
4.	Commitments, Guarantees and Contingencies	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
5.	Acquisition	CSPCo
6.	Benefit Plans	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
7.	Business Segments	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
8.	Income Taxes	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
9.	Financing Activities	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

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

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of new pronouncements issued or implemented in 2008 and standards issued but not implemented that management has determined relate to the Registrant Subsidiaries' operations.

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

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

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

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

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

The Registrant Subsidiaries partially adopted SFAS 157 effective January 1, 2008. The Registrant Subsidiaries will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP SFAS 157-2. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, APCo, CSPCo and OPCo reduced beginning retained earnings by $440 thousand ($286 thousand, net of tax), $486 thousand ($316 thousand, net of tax) and $434 thousand ($282 thousand, net of tax), respectively, for the transition adjustment. SWEPCo's transition adjustment was a favorable $16 thousand ($10 thousand, net of tax) adjustment to beginning retained earnings. The impact of considering AEP's credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption.

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

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

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

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

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

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

The following table sets forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 35,609	$ 1,261,131	$ 10,761	$ (1,012,957)	$ 294,544
Cash Flow and Fair Value Hedges (a)	-	9,201	-	(4,967)	4,234
Dedesignated Risk Management Contracts (b)	-	-	-	14,916	14,916
Total Risk Management Assets	$ 35,609	$ 1,270,332	$ 10,761	$ (1,003,008)	$ 313,694
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 37,928	$ 1,226,686	$ 29,321	$ (1,008,877)	$ 285,058
Cash Flow and Fair Value Hedges (a)	-	34,986	-	(4,967)	30,019
DETM Assignment (c)	-	-	-	7,116	7,116
Total Risk Management Liabilities	$ 37,928	$ 1,261,672	$ 29,321	$ (1,006,728)	$ 322,193

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

CSPCo

Assets:	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Other Cash Deposits (e)	$ 35,806	$ -	$ -	$ 1,169	$ 36,975
Risk Management Assets:					
Risk Management Contracts (a)	$ 21,385	$ 692,082	$ 6,467	$ (557,082)	$ 162,852
Cash Flow and Fair Value Hedges (a)	-	4,503	-	(2,983)	1,520
Dedesignated Risk Management Contracts (b)	-	-	-	8,958	8,958
Total Risk Management Assets	$ 21,385	$ 696,585	$ 6,467	$ (551,107)	$ 173,330
Total Assets	$ 57,191	$ 696,585	$ 6,467	$ (549,938)	$ 210,305
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 22,778	$ 671,311	$ 17,589	$ (553,617)	$ 158,061
Cash Flow and Fair Value Hedges (b)	-	21,011	-	(2,983)	18,028
DETM Assignment (c)	-	-	-	4,274	4,274
Total Risk Management Liabilities	$ 22,778	$ 692,322	$ 17,589	$ (552,326)	$ 180,363

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

I&M

Assets:	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Risk Management Assets:					
Risk Management Contracts (a)	$ 20,545	$ 643,285	$ 6,215	$ (516,431)	$ 153,614
Cash Flow and Fair Value Hedges (a)	-	4,326	-	(2,866)	1,460
Dedesignated Risk Management Contracts (b)	-	-	-	8,606	8,606
Total Risk Management Assets	$ 20,545	$ 647,611	$ 6,215	$ (510,691)	$ 163,680
Spent Nuclear Fuel and Decommissioning Trusts:					
Cash and Cash Equivalents (d)	$ -	$ 16,728	$ -	$ 12,246	$ 28,974
Debt Securities	326,416	507,611	-	-	834,027
Equity Securities	498,926	-	-	-	498,926
Total Spent Nuclear Fuel and Decommissioning Trusts	$ 825,342	$ 524,339	$ -	$ 12,246	$ 1,361,927
Total Assets	$ 845,887	$ 1,171,950	$ 6,215	$ (498,445)	$ 1,525,607
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 21,883	$ 623,352	$ 16,890	$ (512,683)	$ 149,442
Cash Flow and Fair Value Hedges (a)	-	20,186	-	(2,866)	17,320
DETM Assignment (c)	-	-	-	4,107	4,107
Total Risk Management Liabilities	$ 21,883	$ 643,538	$ 16,890	$ (511,442)	$ 170,869

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

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (e)	$ 3,216	$ -	$ -	$ 2,182	$ 5,398
Risk Management Assets:					
Risk Management Contracts (a)	$ 24,915	$ 1,255,573	$ 7,493	$ (1,038,518)	$ 249,463
Cash Flow and Fair Value Hedges (a)	-	5,259	-	(3,475)	1,784
Dedesignated Risk Management Contracts (b)	-	-	-	10,436	10,436
Total Risk Management Assets	$ 24,915	$ 1,260,832	$ 7,493	$ (1,031,557)	$ 261,683
Total Assets	$ 28,131	$ 1,260,832	$ 7,493	$ (1,029,375)	$ 267,081
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 26,538	$ 1,230,208	$ 20,738	$ (1,043,217)	$ 234,267
Cash Flow and Fair Value Hedges (a)	-	27,153	-	(3,475)	23,678
DETM Assignment (c)	-	-	-	4,979	4,979
Total Risk Management Liabilities	$ 26,538	$ 1,257,361	$ 20,738	$ (1,041,713)	$ 262,924

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

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 52,111	$ 562,955	$ 7	$ (515,708)	$ 99,365
Cash Flow and Fair Value Hedges (a)	-	-	-	-	-
Total Risk Management Assets	$ 52,111	$ 562,955	$ 7	$ (515,708)	$ 99,365
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 51,180	$ 560,473	$ 30	$ (517,065)	$ 94,618
Cash Flow and Fair Value Hedges (a)	-	-	-	-	-
DETM Assignment (c)	-	-	-	195	195
Total Risk Management Liabilities	$ 51,180	$ 560,473	$ 30	$ (516,870)	$ 94,813

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

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 61,460	$ 701,896	$ 5	$ (640,985)	$ 122,376
Cash Flow and Fair Value Hedges (a)	-	80	-	(9)	71
Total Risk Management Assets	$ 61,460	$ 701,976	$ 5	$ (640,994)	$ 122,447
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 60,361	$ 698,711	$ 50	$ (643,321)	$ 115,801
Cash Flow and Fair Value Hedges (a)	-	13	-	(9)	4
DETM Assignment (c)	-	-	-	230	230
Total Risk Management Liabilities	$ 60,361	$ 698,724	$ 50	$ (643,100)	$ 116,035

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

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

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

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

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

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 June 30, 2008	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of April 1, 2008	$ (942)	$ (552)	$ (519)	$ (837)	$ (21)	$ (35)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	(532)	(324)	(315)	(327)	1	4
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	261	-	161	-	(5)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(2,186)	(1,313)	(1,261)	(1,530)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(14,900)	(9,194)	(8,580)	(10,712)	(3)	(9)
Balance as of June 30, 2008	$ (18,560)	$ (11,122)	$ (10,675)	$ (13,245)	$ (23)	$ (45)

Six Months Ended June 30, 2008	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of January 1, 2008	$ (697)	$ (263)	$ (280)	$ (1,607)	$ (243)	$ (408)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	(467)	(339)	(312)	232	98	174
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	(1,138)	-	(2,019)	-	(64)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(122)	(188)	(158)	861	232	375
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(17,274)	(9,194)	(9,925)	(10,712)	(110)	(122)
Balance as of June 30, 2008	$ (18,560)	$ (11,122)	$ (10,675)	$ (13,245)	$ (23)	$ (45)

(a) Included in revenues on the Condensed Statement of Income.

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

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

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

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

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

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

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Although management has not completed its analysis, management expects that the adoption of this standard will have an immaterial impact on the financial statements. The Registrant Subsidiaries will adopt SFAS 160 effective January 1, 2009.

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

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

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

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

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

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

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

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

Company	**Retained Earnings Reduction**	**Tax Amount**
	(in thousands)	
APCo	$ 2,181	$ 1,175
CSPCo	1,095	589
I&M	1,398	753
OPCo	1,864	1,004
PSO	1,107	596
SWEPCo	1,156	622

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

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

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

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

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

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

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

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

The Registrant Subsidiaries adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, the Registrant Subsidiaries reclassified the following amounts on their December 31, 2007 balance sheets as shown:

APCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the June 2008 10-Q
Current Assets:		(in thousands)	
Risk Management Assets	$ 64,707	$ (1,752)	$ 62,955
Prepayments and Other	19,675	(3,306)	16,369
Long-term Risk Management Assets	74,954	(2,588)	72,366
Current Liabilities:			
Risk Management Liabilities	54,955	(3,247)	51,708
Customer Deposits	50,260	(4,340)	45,920
Long-term Risk Management Liabilities	47,416	(59)	47,357

CSPCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the June 2008 10-Q
Current Assets:		(in thousands)	
Risk Management Assets	$ 34,564	$ (1,006)	$ 33,558
Prepayments and Other	11,877	(1,917)	9,960
Long-term Risk Management Assets	43,352	(1,500)	41,852
Current Liabilities:			
Risk Management Liabilities	30,118	(1,881)	28,237
Customer Deposits	45,602	(2,507)	43,095
Long-term Risk Management Liabilities	27,454	(35)	27,419

I&M

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the June 2008 10-Q
Current Assets:		(in thousands)	
Risk Management Assets	$ 33,334	$ (969)	$ 32,365
Prepayments and Other	12,932	(1,841)	11,091
Long-term Risk Management Assets	41,668	(1,441)	40,227
Current Liabilities:			
Risk Management Liabilities	29,078	(1,807)	27,271
Customer Deposits	28,855	(2,410)	26,445
Long-term Risk Management Liabilities	26,382	(34)	26,348

OPCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the June 2008 10-Q
		(in thousands)	
Current Assets:			
Risk Management Assets	$ 45,490	$ (1,254)	$ 44,236
Prepayments and Other	20,532	(2,232)	18,300
Long-term Risk Management Assets	51,334	(1,748)	49,586
Current Liabilities:			
Risk Management Liabilities	42,740	(2,192)	40,548
Customer Deposits	33,615	(3,002)	30,613
Long-term Risk Management Liabilities	32,234	(40)	32,194

PSO

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the June 2008 10-Q
		(in thousands)	
Current Assets:			
Risk Management Assets	$ 33,338	$ (30)	$ 33,308
Margin Deposits	9,119	(139)	8,980
Long-term Risk Management Assets	3,376	(18)	3,358
Current Liabilities:			
Risk Management Liabilities	27,151	(33)	27,118
Customer Deposits	41,525	(48)	41,477
Long-term Risk Management Liabilities	2,914	(106)	2,808

SWEPCo

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the June 2008 10-Q
		(in thousands)	
Current Assets:			
Risk Management Assets	$ 39,893	$ (43)	$ 39,850
Margin Deposits	10,814	(164)	10,650
Long-term Risk Management Assets	4,095	(22)	4,073
Current Liabilities:			
Risk Management Liabilities	32,668	(39)	32,629
Customer Deposits	37,537	(64)	37,473
Long-term Risk Management Liabilities	3,460	(126)	3,334

For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2008 balance sheets, the Registrant Subsidiaries netted collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	June 30, 2008	
	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)	
APCo	$ 23,799	$ 19,719
CSPCo	14,288	10,823
I&M	13,724	9,976
OPCo	16,688	21,387
PSO	1,744	3,101
SWEPCo	2,060	4,396

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, management cannot determine the impact on the reporting of the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, hedge accounting, 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 results of operations and financial position.

EXTRAORDINARY ITEM

APCo recorded an extraordinary loss of $118 million ($79 million, net of tax) during the second quarter of 2007 for the establishment of regulatory assets and liabilities related to the Virginia generation operations. In 2000, APCo discontinued SFAS 71 regulatory accounting for the Virginia jurisdiction due to the passage of legislation for customer choice and deregulation. In April 2007, Virginia passed legislation to establish electric regulation again.

3. RATE MATTERS

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

Ohio Rate Matters

Ohio Electric Security Plan Filings – Affecting CSPCo and OPCo

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

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file MROs. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. Effective January 1, 2009, CSPCo and OPCo will defer the fuel cost under-recoveries and related carrying costs for future recovery over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for unexpected costs and reliability costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. Management expects a PUCO decision on the ESP filings in the fourth quarter of 2008.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $45 million and $36 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $28 million and $19 million, respectively. Such costs would be recovered over an 8 year period beginning January 2011. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future results of operations and cash flows.

2008 Generation Rider and Transmission Rider Rate Settlement – Affecting CSPCo and OPCo

On January 30, 2008, the PUCO approved a settlement agreement, among CSPCo, OPCo and other parties, under the additional average 4% generation rate increase and transmission cost recovery rider ("TCRR") provisions of the RSP. The increase was to recover additional governmentally-mandated costs including incremental environmental costs. Under the settlement, the PUCO also approved recovery through the TCRR of increased PJM costs associated with transmission line losses of $39 million each for CSPCo and OPCo. As a result, CSPCo and OPCo established regulatory assets in the first quarter of 2008 of $12 million and $14 million, respectively, related to the future recovery of increased PJM billings from June 2007 to December 2007. The PUCO also approved a credit applied to the TCRR of $10 million for OPCo and $8 million for CSPCo for a reduction in PJM net congestion costs. To the extent that collections for the TCRR items are over/under actual net costs, CSPCo and OPCo will defer the difference and adjust future customer billings to reflect actual costs including carrying costs on the unrecovered deferral. Under the terms of the settlement, although the increased PJM costs associated with transmission line losses will be recovered through the TCRR, these recoveries will still be applied to reduce the annual average 4% generation rate increase limitation. In addition, the PUCO approved recoveries through generation rates of environmental costs and related carrying costs of $29 million for CSPCo and $5 million for OPCo. These RSP rate adjustments were implemented in February 2008.

In February 2008, Ormet, a major industrial customer, filed a motion to intervene and an application for rehearing of the PUCO's January 2008 RSP order claiming the settlement inappropriately shifted $4 million in cost recovery to Ormet. In March 2008, the PUCO granted Ormet's motion to intervene. Ormet's rehearing application also was granted for the purpose of providing the PUCO with additional time to consider the issues raised by Ormet. Management cannot predict the outcome of this rehearing process.

Ohio IGCC Plant – Affecting CSPCo and OPCo

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

In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period CSPCo and OPCo each collected $12 million in pre-construction costs.

The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 costs associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 pending further hearings.

In August 2006, intervenors filed four separate appeals of the PUCO's order in the IGCC proceeding. In March 2008, the Ohio Supreme Court issued its opinion affirming in part, and reversing in part the PUCO's order and remanded the matter back to the PUCO. The Ohio Supreme Court held that while there could be an opportunity under existing law to recover a portion of the IGCC costs in distribution rates, traditional rate making procedures would apply to the recoverable portion. The Ohio Supreme Court did not address the matter of refunding the Phase 1 cost recovery and declined to create an exception to its precedent of denying claims for refund of past recoveries from approved orders of the PUCO.

Recent estimates of the cost to build the proposed IGCC plant are approximately $2.7 billion. Management continues to pursue the ultimate construction of the IGCC plant. However, in light of the Ohio Supreme Court's decision, CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of 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 results of operations and cash flows.

Ormet – Affecting CSPCo and OPCo

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

CSPCo and OPCo each amortized $5 million of this regulatory liability to income for the six months ended June 30, 2008 based on the previously approved 2007 price of $47.69 per MWH. In December 2007, CSPCo and OPCo submitted for approval a market price of $53.03 per MWH for 2008. The PUCO has not yet approved the increase. If the PUCO approves a market price for 2008 below $47.69, it could have an adverse effect on future results of operations and cash flows. A price above $47.69 should result in a favorable effect. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo more profitable market priced off-system sales.

Virginia Rate Matters

Virginia Base Rate Filing – Affecting APCo

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

Virginia E&R Costs Recovery Filing – Affecting APCo

As of June 30, 2008, APCo has $97 million of deferred Virginia incremental E&R costs. Currently APCo is recovering $16 million of the deferral for incremental costs incurred through September 30, 2006. In May 2008, APCo filed for recovery of deferred incremental E&R costs incurred from October 1, 2006 through December 31, 2007 which totals $50 million. The remaining deferral will be requested in a 2009 filing. As of June 30, 2008, APCo has $22 million of unrecorded E&R equity carrying costs of which $7 million should increase 2008 annual earnings as collected. In connection with the 2009 filing, the Virginia SCC will determine the level of incremental E&R costs being collected in base revenues since October 2006 that APCo has estimated to be $48 million annually. If the Virginia SCC were to determine that these recovered base revenues are in excess of $48 million a year, it would require that the E&R deferrals be reduced by the excess amount, thus adversely affecting future earnings and cash flows.

In July 2008, the Old Dominion Committee for Fair Utility Rates (ODC) filed a motion to dismiss the E&R filing based on ODC's belief that the opportunity to collect E&R surcharges expires December 31, 2008. A dismissal would not eliminate APCo's ability to request for future recovery of its deferred E&R costs. APCo filed a response requesting the Virginia SCC to deny ODC's motion. If the Virginia SCC were to disallow any additional portion of APCo's deferral, it would also have an adverse effect on future results of operations and cash flows. If the outstanding request for E&R recovery is approved it will have a favorable effect on future cash flows.

Virginia Fuel Clause Filings – Affecting APCo

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

In February 2008, the Virginia SCC issued an order that approved a reduced fuel factor effective with the February 2008 billing cycle. The order terminated the off-system sales margin rider and approved a 75%-25% sharing of off-system sales margins between customers and APCo effective September 1, 2007 as required by the re-regulation legislation in Virginia. The order also allows APCo to include in its monthly under/over recovery deferrals the Virginia jurisdictional share of PJM transmission line loss costs from June 2007 to June 2008 which totaled $28 million. The adjusted factor increases annual revenues by $4 million. The order authorized the Virginia SCC staff and other parties to make specific recommendations to the Virginia SCC in APCo's next fuel factor proceeding to ensure accurate assignment of the prudently incurred PJM transmission line loss costs to APCo's Virginia jurisdictional operations. Management believes the incurred PJM transmission line loss costs are prudently incurred and are being properly assigned to APCo's Virginia jurisdictional operations.

In February 2008, the Old Dominion Committee for Fair Utility Rates (ODC) filed a notice of appeal to the Supreme Court of Virginia appealing the Virginia SCC's decisions regarding off-system sales margins and PJM transmission line loss costs. In May 2008, the ODC withdrew its appeal.

In July 2008, APCo filed its next fuel factor proceeding with the Virginia SCC and requested an annualized increase of $132 million effective September 1, 2008. The increase primarily relates to increases in coal costs.

If costs included in APCo's Virginia fuel under/over recovery deferrals are disallowed, it could result in an adverse effect on future results of operations and cash flows.

APCo's Virginia SCC Filing for an IGCC Plant – Affecting APCo

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

The Virginia SCC issued an order in April 2008 denying APCo's requests stating the belief that the estimated cost may be significantly understated. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In April 2008, APCo filed a petition for reconsideration in Virginia. In May 2008, the Virginia SCC denied APCo's request to reconsider its previous ruling. In July 2008, the IRS awarded $134 million in future tax credits for the IGCC plant. Management continues to pursue the ultimate construction of the IGCC plant; however, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is canceled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is canceled and the deferred costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

West Virginia Rate Matters

APCo's 2008 Expanded Net Energy Cost (ENEC) Filing – Affecting APCo

In February 2008, APCo filed for an increase of approximately $140 million including a $122 million increase in the ENEC, a $15 million increase in construction cost surcharges and $3 million of reliability expenditures, to become effective July 2008. In June 2008, the WVPSC issued an order approving a joint stipulation and settlement agreement granting an increase, effective July 2008, of approximately $95 million, including a $79 million increase in the ENEC, a $13 million increase in construction cost surcharges and $3 million of reliability expenditures. The ENEC is an expanded form of fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits, PJM costs associated with transmission line losses due to the implementation of marginal loss pricing and other energy/transmission items.

The ENEC is subject to a true up to actual costs and should have no earnings effect due to the deferral of any over/under-recovery of actual ENEC costs. The construction cost and reliability surcharges are not subject to a true up to actual costs and could result in an adverse under recovery.

APCo's West Virginia IGCC Plant Filing – Affecting APCo

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

In June 2007, APCo filed testimony with the WVPSC supporting the requests for a CCN and for pre-approval of a surcharge rate mechanism to provide for the timely recovery of both pre-construction costs and the ongoing finance costs of the project during the construction period as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. In March 2008, the WVPSC granted APCo the CCN to build the plant and the request for cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order. At the time of the filing, the cost of the plant was estimated at $2.2 billion. In July 2008, based on the order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed (See the "APCo's Virginia SCC Filing for an IGCC Plant" section above). Through June 30, 2008, APCo deferred for future recovery pre-construction IGCC costs of $8 million applicable to the West Virginia jurisdiction and $2 million applicable to the FERC jurisdiction. In July 2008, the IRS awarded $134 million in future tax credits for the IGCC plant. Management continues to pursue the ultimate construction of the IGCC plant; however, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is canceled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is canceled and the deferred costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

Indiana Rate Matters

Indiana Rate Filing – Affecting I&M

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase includes the $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. The depreciation reduction will no longer favorably impact earnings if and when tariff rates are revised to reflect the reduction. The filing requests trackers for certain variable components of the cost of service including recently increased PJM costs associated with transmission line losses due to the implementation of marginal loss pricing and other RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and environmental compliance costs. The trackers would initially increase annual revenues by an additional $45 million. I&M proposes to share with ratepayers, through a tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million. A decision is expected from the IURC by June 2009.

Oklahoma Rate Matters

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

In 2004, intervenors and the OCC staff argued that AEP had inappropriately under allocated off-system sales credits to PSO by $37 million for the period June 2000 to December 2004 under a FERC-approved allocation agreement. An ALJ assigned to hear intervenor claims found that the OCC lacked authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In October 2007, the OCC adopted the ALJ's recommendation and orally directed the OCC staff to explore filing a complaint at FERC alleging the allocation of off-system sales margins to PSO is not in compliance with the FERC-approved methodology which could result in an adverse effect on future results of operations and cash flows for AEP Consolidated and the AEP East companies. In June 2008, the ALJ issued a final recommendation and incorporated the prior finding that the OCC lacked authority to review AEP's application of a FERC-approved methodology. The OCC is scheduled to consider the final recommendation in August 2008. To date, no claim has been asserted at the FERC and management continues to believe that the allocation is consistent with the FERC-approved agreement.

In February 2006, the OCC enacted a rule, requiring the OCC staff to conduct prudence reviews on PSO's generation and fuel procurement processes, practices and costs on a periodic basis. PSO filed testimony in June 2007 covering a prudence review for the year 2005. The OCC staff and intervenors filed testimony in September 2007, and hearings were held in November 2007. The only major issue in the proceeding was the alleged under allocation of off-system sales credits under the FERC-approved allocation methodology, which was determined not to be jurisdictional to the OCC. Consistent with her prior recommendation, the ALJ found that the OCC lacked authority to alter the FERC-approved methodology and that PSO's fuel costs were prudent. The OCC is scheduled to consider the ALJ's findings and rule in August 2008.

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

Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings and prudence reviews or whether a complaint will be filed at FERC regarding the off-system sales allocation issue. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and that it allocated off-system sales credits consistent with governing FERC-approved agreements. If a complaint is filed at FERC resulting in an unfavorable decision, it could have an adverse effect on results of operations and cash flows.

Red Rock Generating Facility – Affecting PSO

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

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

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

Oklahoma 2007 Ice Storms – Affecting PSO

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

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

In June 2008, PSO adjusted its regulatory asset to true-up the estimated costs to reflect actual costs as of June 30, 2008. After the true-up, application of proceeds from to-date sales of excess SO_2 emission allowances and carrying costs, the ice storm regulatory asset as of June 30, 2008 was $64 million. In July 2008, PSO filed with the OCC to establish the recovery rider and the final recoverable December 2007 ice storm costs. The estimate of future gains from the sale of SO_2 emission allowances has significantly declined with the decrease in value of such allowances. As a result, estimated collections from customers through the special storm damage recovery rider will be higher than the estimate in the settlement agreement. Nonetheless, management believes that the settlement provides for full recovery of the remaining deferral.

2008 Oklahoma Annual Fuel Factor Filing – Affecting PSO

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

2008 Oklahoma Base Rate Filing – Affecting PSO

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million on an annual basis. PSO recovers costs related to new peaking units recently placed into service through the Generation Cost Recovery Rider (GCRR). Upon implementation of the new base rates, PSO will recover these costs through the new base rates and the GCRR will terminate. Therefore, PSO’s net annual requested increase in total revenues is $117 million. The requested increase is based upon a test year ended February 29, 2008, adjusted for known and measurable changes through August 2008, which is consistent with the ratemaking treatment adopted by the OCC in PSO’s 2006 base rate case. The proposed revenue requirement reflects a return on equity of 11.25%. PSO expects hearings to begin in December 2008 and new rates effective in the first quarter of 2009.

<u>Louisiana Rate Matters</u>

Louisiana Compliance Filing – Affecting SWEPCo

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

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

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

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

In April 2008, SWEPCo filed the first FRP which would increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%. In June 2008, SWEPCo recorded a $3 million regulatory liability related to the reduction in generation depreciation rates.

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 estimated to cost $378 million, excluding AFUDC, and is expected to be in-service in mid-2010.

In March 2007, the PUCT approved SWEPCo's request for a certificate for the facility based on a prior cost estimate. In February 2008, the LPSC staff submitted testimony in support of the Stall Unit and one intervenor submitted testimony opposing the Stall Unit due to the increase in cost. The LPSC held hearings in April 2008. In July 2008, an ALJ in the LPSC proceeding recommended approval of the Stall Unit. The APSC has not established a procedural schedule at this time. The Louisiana Department of Environmental Quality issued an air permit for the unit in March 2008. If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized pre-construction costs including any cancellation fees. As of June 30, 2008, SWEPCo has capitalized pre-construction costs of $106 million and has contractual construction commitments of an additional $191 million. As of June 30, 2008, if the plant had been canceled, cancellation fees of $60 million would have been required in order to terminate these construction commitments. If SWEPCo canceled the plant and cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future results of operations and cash flows.

Turk Plant – Affecting SWEPCo

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

<u>Arkansas Rate Matters</u>

Turk Plant – Affecting SWEPCo

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

In November 2007, the APSC granted approval to build the plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant. In July 2008, the PUCT approved a certificate of convenience and necessity for construction of the plant. We expect a written order in August 2008 which will also provide for the conditions of the PUCT's approval.

SWEPCo is working with the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers for approval later this year. A request to stop pre-construction activities at the site was filed in Federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the Federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of June 30, 2008, including the joint owners' share, SWEPCo has capitalized approximately $407 million of expenditures and has significant contractual construction commitments for an additional $815 million. As of June 30, 2008, if the plant had been canceled, cancellation fees of $60 million would have been required in order to terminate these construction commitments. If SWEPCo cannot recover its costs, it would have an adverse effect on future results of operations, cash flows and possibly financial condition.

Stall Unit – Affecting SWEPCo

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

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC's direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load 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 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. As a result, SECA ratepayers have been willing to engage with AEP in settlement discussions. AEP has been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

During 2006, the AEP East companies provided reserves of $37 million for net refunds for current and future SECA settlements. After reviewing existing settlements, the AEP East companies increased their reserves by an additional $5 million in December 2007. APCo's, CSPCo's, I&M's and OPCo's portions of the provision are as follows:

Company	2007	2006
	(in millions)	
APCo	$ 1.7	$ 12.0
CSPCo	0.9	6.7
I&M	1.0	7.0
OPCo	1.3	9.1

Completed and in-process settlements cover $107 million of the $220 million of SECA revenues and will consume about $7 million of the reserve for refund, leaving approximately $113 million of contested SECA revenues and $35 million of refund reserves.

If the FERC adopts the ALJ's decision and/or AEP cannot settle the remaining unsettled claims within the amount reserved for refunds, it will have an adverse effect on future results of operations and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $35 million is adequate to cover all remaining settlements. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if such are necessary.

The FERC PJM Regional Transmission Rate Proceeding

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

The AEP East companies filed for and in 2006 obtained increases in its wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 85% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future results of operations and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 15% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

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

PJM Transmission Formula Rate Filing – Affecting APCo, CSPCo, I&M and OPCo

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in additional annual revenues of approximately $9 million from nonaffiliated customers within PJM. AEP requested an effective date of October 1, 2008. Retail rates are not immediately affected by the filing at the FERC, but retail rates in Ohio would reflect the revised FERC transmission rate through the Transmission Cost Recovery Rider (TCRR) effective January 2009 resulting in additional annual revenues of approximately $22 million. Management is unable to predict the outcome of this filing.

SPP Transmission Formula Rate Filing – Affecting PSO and SWEPCo

In June 2007, AEPSC filed revised tariffs to establish an up-to-date revenue requirement for SPP transmission services over the facilities owned by PSO and SWEPCo and to implement a transmission cost of service formula rate. PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. If approved as filed, the revised tariff will increase annual network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP pricing zone of SPP by approximately $10 million. In August 2007, the FERC issued an order conditionally accepting PSO’s and SWEPCo’s proposed formula rate, subject to a compliance filing, suspended the effective date until February 1, 2008 and established a hearing schedule and settlement judge proceedings. New rates, subject to refund, were implemented in February 2008. Multiple intervenors have protested or requested re-hearing of the order and settlement discussions are underway. Management believes it has recognized the appropriate amount of revenues, subject to refund, since implemented in February 2008. Management is unable to predict the outcome of this proceeding.

FERC Market Power Mitigation – Affecting APCo, CSPCo, I&M and OPCo

The FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that the FERC should further investigate whether AEP continues to pass the FERC’s indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged the FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with the FERC’s guidelines, and continue to demonstrate lack of market power. Management is unable to predict the outcome of this proceeding; however, if a further investigation by the FERC limited AEP’s ability to sell power at market based rates in PJM, it would result in an adverse effect on future off-system sales margins, results of operations and cash flows.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2007 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

Certain Registrant Subsidiaries enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits and debt service reserves. These LOCs were issued in the Registrant Subsidiaries' ordinary course of business under the two $1.5 billion credit facilities.

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. As of June 30, 2008, $371 million of letters of credit were issued by Registrant Subsidiaries under the 3-year credit agreement to support variable rate demand notes.

At June 30, 2008, the maximum future payments of the LOCs were as follows:

Company	Amount (in thousands)	Maturity	Borrower Sublimit
$1.5 billion LOC:			
I&M	$ 1,113	March 2009	N/A
SWEPCo	4,000	December 2008	N/A
$650 million LOC:			
APCo	$ 126,717	June 2009	$ 300,000
I&M	77,886	May 2009	230,000
OPCo	166,899	June 2009	400,000

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of June 30, 2008, SWEPCo collected approximately $36 million through a rider for final mine closure costs, of which approximately $7 million is recorded in Other Current Liabilities and $29 million is recorded in Deferred Credits and Other on SWEPCo's Condensed Consolidated Balance Sheets.

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

Indemnifications and Other Guarantees

Contracts

All of the Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to June 30, 2008, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary. There are no material liabilities recorded for any indemnifications.

The AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. At June 30, 2008, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss (in millions)
APCo	$ 10
CSPCo	5
I&M	7
OPCo	10
PSO	6
SWEPCo	6

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. AEP intends to maintain the lease for twenty years, via renewal options. Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 84% to 77% of the projected fair market value of the equipment.

In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as new operating leases for I&M and SWEPCo. The future minimum lease obligation is $21 million for I&M and $24 million for SWEPCo as of June 30, 2008. I&M and SWEPCo intend to renew these leases for the full remaining terms and have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee discussed above is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $14 million ($9 million, net of tax). However, management believes that the fair market value would produce a sufficient sales price to avoid any loss.

The Registrant Subsidiaries have other railcar lease arrangements that do not utilize this type of financing structure.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting CSPCo

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. The alleged modifications occurred over a 20-year period. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units.

The AEP System settled their cases in 2007. A case is still pending that could affect CSPCo's share of jointly-owned units at Stuart Station. The Stuart units, operated by DP&L, are equipped with SCR and flue gas desulfurization equipment (FGD or scrubbers) controls. A trial on liability issues was scheduled for August 2008.

The Court issued a stay to allow the parties to pursue settlement discussions. Those discussions are ongoing. Another case involving a jointly-owned Beckjord unit had a liability trial in May 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit.

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 its jointly-owned plants. 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 market prices of electricity. If CSPCo is unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs' attorneys' fees and costs. The consent decree was entered as a final order in June 2008.

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

In February 2008, the Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that the permit alteration issued by TCEQ was improper. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit.

Management is unable to predict the timing of any future action by the Federal EPA or the effect of such action on results of operations, cash flows or financial condition.

Carbon Dioxide (CO_2) Public Nuisance Claims – Affecting AEP East companies and AEP West companies

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

Alaskan Villages' Claims – Affecting AEP East companies and AEP West companies

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. Management believes the action is without merit and intends to defend against the claims.

Clean Air Act Interstate Rule – Affecting Registrant Subsidiaries

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

In anticipation of compliance with CAIR in 2009, I&M purchased $8 million of annual CAIR NO_x allowances which are included in inventory as of June 30, 2008. The market value of annual CAIR NO_x allowances decreased in the weeks following this court decision. Management intends to seek recovery of the cost of purchased allowances. If the recovery is denied, it would have an adverse effect on future results of operations and cash flows. None of the other Registrant Subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to the Registrant Subsidiaries' facilities under the Acid Rain Program and the NO_X SIP Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

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

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting I&M

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms and recorded approximately $1 million of expense. As the remediation work is completed, I&M's cost may increase. I&M cannot predict the amount of additional cost, if any. At present, management's estimates do not anticipate material cleanup costs for this site.

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.

FERC Long-term Contracts – Affecting AEP East companies and AEP West companies

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. The Registrant Subsidiaries asserted claims against certain companies that sold power to them, which was resold to the Nevada utilities, seeking to recover a portion of any amounts the Registrant Subsidiaries may owe to the Nevada utilities.

5. ACQUISITION

2008

None

2007

Darby Electric Generating Station – Affecting CSPCo

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

6. BENEFIT PLANS

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 23	$ 11	$ 11
Interest Cost	62	57	28	26
Expected Return on Plan Assets	(84)	(82)	(28)	(26)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	10	14	2	3
Net Periodic Benefit Cost	$ 13	$ 12	$ 20	$ 21

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 50	$ 47	$ 21	$ 21
Interest Cost	125	116	56	52
Expected Return on Plan Assets	(168)	(167)	(56)	(52)
Amortization of Transition Obligation	-	-	14	14
Amortization of Net Actuarial Loss	19	29	5	6
Net Periodic Benefit Cost	$ 26	$ 25	$ 40	$ 41

The following tables provide the Registrant Subsidiaries' net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
Company	2008	2007	2008	2007
	(in thousands)			
APCo	$ 834	$ 842	$ 3,700	$ 3,560
CSPCo	(349)	(258)	1,499	1,491
I&M	1,820	1,900	2,423	2,531
OPCo	320	245	2,817	2,801
PSO	508	424	1,387	1,430
SWEPCo	936	747	1,376	1,419

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
Company	2008	2007	2008	2007
	(in thousands)			
APCo	$ 1,669	$ 1,684	$ 7,399	$ 7,120
CSPCo	(698)	(515)	2,997	2,982
I&M	3,641	3,800	4,846	5,061
OPCo	639	490	5,633	5,603
PSO	1,016	848	2,774	2,861
SWEPCo	1,871	1,493	2,752	2,838

7. BUSINESS SEGMENTS

The Registrant Subsidiaries have one reportable segment. The one reportable segment is an electricity generation, transmission and distribution business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed as one segment because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. INCOME TAXES

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

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

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, AEP has filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. The Registrant Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Tax Legislation – Affecting APCo, CSPCo and OPCo

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of a new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. AEP filed applications for the West Virginia and Ohio IGCC projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during the first round of credit awards. After one of the original credit recipients surrendered their credits in the Fall of 2007, the IRS announced a supplemental credit round for the Spring of 2008. AEP filed a new application in 2008 for the West Virginia IGCC project and in July 2008 the IRS awarded the project $134 million in credits subject to entering into a memorandum of understanding with the IRS.

State Tax Legislation – Affecting APCo, CSPCo, I&M and OPCo

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

9. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2008 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Pollution Control Bonds	$ 75,000	Variable	2036
APCo	Pollution Control Bonds	50,275	Variable	2036
APCo	Senior Unsecured Notes	500,000	7.00	2038
CSPCo	Senior Unsecured Notes	350,000	6.05	2018
I&M	Pollution Control Bonds	25,000	Variable	2019
I&M	Pollution Control Bonds	52,000	Variable	2021
I&M	Pollution Control Bonds	40,000	5.25	2025
OPCo	Pollution Control Bonds	50,000	Variable	2014
OPCo	Pollution Control Bonds	50,000	Variable	2014
OPCo	Pollution Control Bonds	65,000	Variable	2036
SWEPCo	Senior Unsecured Notes	400,000	6.45	2019

Company	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Senior Unsecured Notes	$ 200,000	3.60	2008
APCo	Pollution Control Bonds	40,000	Variable	2019
APCo	Pollution Control Bonds	30,000	Variable	2019
APCo	Pollution Control Bonds	17,500	Variable	2021
APCo	Pollution Control Bonds	50,275	Variable	2036
APCo	Pollution Control Bonds	75,000	Variable	2037
APCo	Other	7	13.718	2026
CSPCo	Senior Unsecured Notes	52,000	6.51	2008
CSPCo	Senior Unsecured Notes	60,000	6.55	2008
CSPCo	Pollution Control Bonds	48,550	Variable	2038
CSPCo	Pollution Control Bonds	43,695	Variable	2038
I&M	Pollution Control Bonds	45,000	Variable	2009
I&M	Pollution Control Bonds	25,000	Variable	2019
I&M	Pollution Control Bonds	52,000	Variable	2021
I&M	Pollution Control Bonds	50,000	Variable	2025
I&M	Pollution Control Bonds	40,000	Variable	2025
I&M	Pollution Control Bonds	50,000	Variable	2025
OPCo	Notes Payable	1,463	6.81	2008
OPCo	Notes Payable	6,000	6.27	2009
OPCo	Pollution Control Bonds	50,000	Variable	2014
OPCo	Pollution Control Bonds	50,000	Variable	2016
OPCo	Pollution Control Bonds	50,000	Variable	2022
OPCo	Pollution Control Bonds	35,000	Variable	2022
OPCo	Pollution Control Bonds	65,000	Variable	2036
PSO	Pollution Control Bonds	33,700	Variable	2014
SWEPCo	Notes Payable	1,500	Variable	2008
SWEPCo	Notes Payable	2,203	4.47	2011

As of June 30, 2008, OPCo and SWEPCo had $218 million and $95 million, respectively, of tax-exempt long-term debt sold at auction rates that reset every 35 days. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation and Financial Guaranty Insurance Co. Due to the exposure that these bond insurers have in connection with recent developments in the subprime credit market, the credit ratings of these insurers have been downgraded or placed on negative outlook. These market factors have contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including many of the auctions of tax-exempt long-term debt. The instruments under which the bonds are issued allow for conversion to other short-term variable-rate structures, term-put structures and fixed-rate structures. Through June 30, 2008, the Registrant Subsidiaries reduced their outstanding auction rate securities. Management plans to continue this conversion and refunding process for the remaining $313 million to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, during the second half of 2008 to lower interest rates as such opportunities arise.

As of June 30, 2008, $367 million of the prior auction rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 1.45% to 1.68% and $222 million was issued at fixed rates ranging from 4.85% to 5.25%. As of June 30, 2008, trustees held, on behalf of the Registrant Subsidiaries, approximately $400 million of their reacquired auction rate tax-exempt long-term debt which management plans to reissue to the public as market conditions permit. The following table shows the current status of debt which was issued as auction rate debt at December 31, 2007:

Company	Retired in 2008	Remarketed at Fixed Rates During the First Six Months of 2008	Fixed Rate at June 30, 2008	Remarketed at Variable Rates During the First Six Months of 2008	Variable Rate at June 30, 2008	Remains at Auction Rate at June 30, 2008	Held by Trustee at June 30, 2008
	(in thousands)			(in thousands)		(in thousands)	
APCo	$ -	$ -	-%	$ 75,000	1.62%	$ -	$ 87,500
APCo	-	-	-%	50,275	1.68%	-	-
CSPCo	-	56,000	5.10%	-	-%	-	92,245
CSPCo	-	44,500	4.85%	-	-%	-	-
I&M	45,000	40,000	5.25%	52,000	1.57%	-	100,000
I&M	-	-	-%	25,000	1.50%	-	-
OPCo	-	-	-%	65,000	1.60%	218,000	85,000
OPCo	-	-	-%	50,000	1.45%	-	-
OPCo	-	-	-%	50,000	1.47%	-	-
PSO	-	-	-%	-	-%	-	33,700
SWEPCo	-	81,700	4.95%	-	-%	94,635	-
Total	$ 45,000	$ 222,200		$ 367,275		$ 312,635	$ 398,445

Lines of Credit

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of June 30, 2008 and December 31, 2007 are included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the six months ended June 30, 2008 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of June 30, 2008	Authorized Short-Term Borrowing Limit
	(in thousands)					
APCo	$ 307,226	$ 269,987	$ 226,292	$ 187,192	$ (103,802)	$ 600,000
CSPCo	238,172	150,358	157,569	65,413	25,199	350,000
I&M	345,064	-	174,380	-	(272,707)	500,000
OPCo	415,951	-	165,436	-	(173,833)	600,000
PSO	128,114	59,384	61,023	29,811	(110,981)	300,000
SWEPCo	168,495	300,525	87,426	273,118	300,525	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Six Months Ended June 30, 2008	2007
Maximum Interest Rate	5.37%	5.46%
Minimum Interest Rate	2.91%	5.30%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2008 and 2007 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Six Months Ended June 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for the Six Months Ended June 30,	
Company	2008	2007	2008	2007
APCo	3.86%	5.36%	3.25%	-%
CSPCo	3.66%	5.37%	2.93%	5.33%
I&M	3.30%	5.35%	-%	-%
OPCo	3.39%	5.35%	-%	5.43%
PSO	3.03%	5.36%	4.53%	-%
SWEPCo	3.36%	5.36%	2.93%	5.34%

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		June 30, 2008		December 31, 2007	
Company	Type of Debt	Outstanding Amount (in thousands)	Interest Rate	Outstanding Amount (in thousands)	Interest Rate
OPCo	Commercial Paper – JMG	$ -	- %	$ 701	5.35 %
SWEPCo	Line of Credit – Sabine Mining Company	7,039	3.25 %	285	5.25 %

Credit Facilities

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. Under the facilities, letters of credit may be issued. As of June 30, 2008, $371 million of letters of credit were issued by Registrant Subsidiaries under the 3-year credit agreement to support variable rate demand notes.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements and (iii) footnotes of each individual registrant. The combined Management's Discussion and Analysis of Registrant Subsidiaries section of the 2007 Annual Report should also be read in conjunction with this report.

Sources of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program under two $1.5 billion revolving credit facilities which support the Utility Money Pool. In March 2008, these credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit (LOC). Certain companies within the AEP System including the Registrant Subsidiaries operate the Utility Money Pool to minimize external short-term funding requirements. The Registrant Subsidiaries also sell accounts receivable to provide liquidity. The Registrant Subsidiaries generally use short-term funding sources (the Utility Money Pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from AEP.

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. The Registrant Subsidiaries may issue LOCs under the credit facilities. Each subsidiary has a borrowing/LOC limit under the credit facilities. As of June 30, 2008, a total of $371 million of LOCs were issued under the 3-year credit agreement to support variable rate demand notes. The following table shows each Registrant Subsidiaries' borrowing/LOC limit under each credit facility and the outstanding amount of LOCs for the $650 million facility.

Company	$650 million Credit Facility Borrowing/LOC Limit	$350 million Credit Facility Borrowing/LOC Limit	LOC Amount Outstanding Against $650 million Agreement at June 30, 2008
		(in millions)	
APCo	$ 300	$ 150	$ 127
CSPCo	230	120	-
I&M	230	120	77
OPCo	400	200	167
PSO	65	35	-
SWEPCo	230	120	-

At June 30, 2008, there were no outstanding amounts under the $350 million facility.

Credit Markets

Management believes the Registrant Subsidiaries, through the Utility Money Pool, have adequate liquidity under credit facilities and the ability to issue long-term debt in the current credit markets. As of June 30, 2008, OPCo had $218 million and SWEPCo had $95 million outstanding of tax-exempt long-term debt sold at auction rates that reset every 35 days. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation and Financial Guaranty Insurance Co. Due to the exposure that these bond insurers have in connection with developments in the subprime credit market, the credit ratings of these insurers have been downgraded or placed on negative outlook. These market factors have contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including many of the auctions of tax-exempt long-term debt. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. Through June 30, 2008, the Registrant Subsidiaries reduced their outstanding auction rate securities. Management plans to continue the conversion and refunding process for the remaining $313 million to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, during the second half of 2008 to lower interest rates as such opportunities arise.

As of June 30, 2008, trustees held, on behalf of the Registrant Subsidiaries, approximately $400 million of their reacquired auction rate tax-exempt long-term debt which management plans to reissue to the public as the market permits. The following table shows the current status of debt that was issued as auction rate at December 31, 2007 by Registrant Subsidiary.

Company	Retired in 2008	Remarketed at Fixed or Variable Rates During the First Half of 2008	Remains in Auction Rate at June 30, 2008	Held by Trustee at June 30, 2008
	(in millions)			
APCo	$ -	$ 125	$ -	$ 88
CSPCo	-	101	-	92
I&M	45	117	-	100
OPCo	-	165	218	85
PSO	-	-	-	34
SWEPCo	-	82	95	-

APCo, I&M and OPCo issued $125 million, $77 million and $165 million, respectively, of weekly variable rate debt. As of June 30, 2008, the variable rates ranged from 1.45% to 1.68%. CSPCo issued fixed rate debt of $45 million at 4.85% until 2012 and $56 million at 5.1% until 2013. I&M issued $40 million of fixed rate debt at 5.25% due 2025. SWEPCo remarketed $82 million of fixed rate debt at 4.95% due 2018.

Budgeted Construction Expenditures

Revised construction expenditures for the Registrant Subsidiaries for 2009 and 2010 are:

Company	Estimated Construction Expenditures 2009	2010
	(in millions)	
APCo	$ 583.2	$ 474.4
CSPCo	311.7	308.3
I&M	457.7	496.8
OPCo	441.1	410.9
PSO	257.2	419.2
SWEPCo	710.3	681.0

The budgeted amounts increased for I&M and SWEPCo and decreased for APCo, CSPCo, OPCo and PSO.

Significant Factors

Ohio Electric Security Plan Filings

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

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file MROs. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. Effective January 1, 2009, CSPCo and OPCo will defer the fuel cost under-recoveries and related carrying costs for future recovery over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for unexpected costs and reliability costs. The filings also include programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. Management expects a PUCO decision on the ESP filings in the fourth quarter of 2008.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $45 million and $36 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $28 million and $19 million, respectively. Such costs would be recovered over an 8 year period beginning January 2011. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future results of operations and cash flows.

FERC Market Power Mitigation

The FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that the FERC should further investigate whether AEP continues to pass the FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged the FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with the FERC's guidelines, and continue to demonstrate lack of market power. Management is unable to predict the outcome of this proceeding; however, if a further investigation by the FERC limited AEP's ability to sell power at market based rates in PJM, it would result in an adverse effect on future off-system sales margins, results of operations and cash flows.

New Generation

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

Operating Company	Project Name		Location	Total Projected Cost (a)	CWIP (b)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
				(in millions)	(in millions)				
PSO	Southwestern	(c)	Oklahoma	$ 56	$ -	Gas	Simple-cycle	150	2008
PSO	Riverside	(d)	Oklahoma	58	-	Gas	Simple-cycle	150	2008
AEGCo	Dresden	(e)	Ohio	309(e)	119	Gas	Combined-cycle	580	2010
SWEPCo	Stall		Louisiana	378	106	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(f)	Arkansas	1,522(f)	407	Coal	Ultra-supercritical	600(f)	2012
APCo	Mountaineer	(g)	West Virginia	2,230(g)	-	Coal	IGCC	629	2012(g)
CSPCo/OPCo	Great Bend	(g)	Ohio	2,700(g)	-	Coal	IGCC	629	2017(g)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC. Turk's CWIP includes joint owners' share.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) The final Riverside Unit was placed in service on June 15, 2008.
(e) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(f) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1,110 million in capital investment. The increase in the cost estimate disclosed in the 2007 Annual Report relates to cost escalations due to the delay in receipt of permits and approvals. See "Turk Plant" section below.
(g) Subject to revision; construction of IGCC plants deferred pending regulatory approval. See "IGCC Plants" section below.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant. In July 2008, the PUCT approved a certificate of convenience and necessity for construction of the plant. We expect a written order in August 2008 which will also provide for the conditions of the PUCT's approval.

SWEPCo is working with the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers for approval later this year. A request to stop pre-construction activities at the site was filed in Federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the Federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

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 the joint owners for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of June 30, 2008, including the joint owners' share, SWEPCo has capitalized approximately $407 million of expenditures and has significant contractual construction commitments for an additional $815 million. As of June 30, 2008, if the plant had been canceled, cancellation fees of $60 million would have been required in order to terminate these construction commitments. If SWEPCo cannot recover its costs, it would have an adverse effect on future results of operations, cash flows and possibly financial condition.

IGCC Plants

We have delayed construction of the West Virginia and Ohio IGCC plants. In May 2008, the Virginia SCC denied APCo's request to reconsider the Virginia SCC previous denial of APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. In July 2008, the IRS awarded $134 million in future tax credits for the IGCC plant. Management continues to pursue the ultimate construction of the IGCC plant. If the West Virginia IGCC plant is canceled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs of $19 million. If the plant is canceled and the deferred costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

In Ohio, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant, but await the result of an Ohio Supreme Court remand to the PUCO regarding recovery of IGCC pre-construction costs. If CSPCo and OPCo were required to refund $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 results of operations and cash flows.

Environmental Matters

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

- Requirements under the CAA to reduce emissions of SO_2, NO_x, 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 engaged 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 2007 Annual Report.

Environmental Litigation

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

In 2007, the AEP System settled their complaints under a consent decree. CSPCo jointly-owned Beckjord and Stuart Stations with Duke and DP&L. A jury trial in May 2008 returned a verdict of no liability at the jointly-owned Beckjord unit. Settlement discussions are ongoing in the citizen suit action filed by Sierra Club against the jointly-owned units at Stuart Station. 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 for electricity. If CSPCo is unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations and cash flows.

Clean Air Act Requirements

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

In anticipation of compliance with CAIR in 2009, I&M purchased $8 million of annual CAIR NO_x allowances which are included in inventory as of June 30, 2008. The market value of annual CAIR NO_x allowances decreased in the weeks following this court decision. Management intends to seek recovery of the cost of purchased allowances. If the recovery is denied, it would have an adverse effect on future results of operations and cash flows. None of the other Registrant Subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to the Registrant Subsidiaries' facilities under the Acid Rain Program and the NO_X SIP Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

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

Global Climate Change

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

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

Clean Water Act Regulation

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

Company	Estimated Compliance Investments (in millions)
APCo	$ 21
CSPCo	19
I&M	118
OPCo	31

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

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

Adoption of New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data. In February 2008, the FASB issued FSP

FAS 157-1 “Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13” which amends SFAS 157 to exclude SFAS 13 “Accounting for Leases” and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB issued FSP FAS 157-2 “Effective Date of FASB Statement No. 157” which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. The Registrant Subsidiaries partially adopted SFAS 157 effective January 1, 2008. The Registrant Subsidiaries will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, APCo, CSPCo and OPCo reduced beginning retained earnings by $440 thousand ($286 thousand, net of tax), $486 thousand ($316 thousand, net of tax) and $434 thousand ($282 thousand, net of tax), respectively, for the transition adjustment. SWEPCo’s transition adjustment was a favorable $16 thousand ($10 thousand, net of tax) adjustment to beginning retained earnings. The impact of considering AEP’s credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption. See “SFAS 157 “Fair Value Measurements” (SFAS 157)” section of Note 2.

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

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

Company	Retained Earnings Reduction	Tax Amount
	(in thousands)	
APCo	$ 2,181	$ 1,175
CSPCo	1,095	589
I&M	1,398	753
OPCo	1,864	1,004
PSO	1,107	596
SWEPCo	1,156	622

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

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

Company	**(in thousands)**
APCo	$ 7,646
CSPCo	4,423
I&M	4,251
OPCo	5,234
PSO	187
SWEPCo	229

CONTROLS AND PROCEDURES

During the second quarter of 2008, management, including the principal executive officer and principal financial officer of each of AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2008 these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2008 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 4, *Commitments, Guarantees and Contingencies*, incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2007 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2007 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Our request for rate recovery in Oklahoma may not be approved. *(Applies to AEP and PSO)*

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million on an annual basis (including an estimated $16 million that is being recovered through a rider). The proposed revenue requirement reflects a return on equity of 11.25%. If the OCC denies all or part of the requested rate recovery, it could have an adverse effect on future results of operations, cash flows and financial condition.

Our request for rate recovery in Ohio may not be approved. *(Applies to AEP, OPCo and CSPCo)*

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. Management expects a PUCO decision on the ESP filings in the fourth quarter of 2008. If the PUCO denies all or part of the requested rate recovery, it could have an adverse effect on future results of operations, cash flows and financial condition.

Risks Related to Owning and Operating Generation Assets and Selling Power

The different regional power markets in which we compete or will compete in the future have changing transmission regulatory structures, which could affect our performance in these regions. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. In December 2007, AEP filed its most recent triennial update. In 2008, the PUCO filed comments suggesting that FERC should further investigate whether certain utilities, including AEP, continue to pass FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged FERC to further investigate this matter.

If FERC limits AEP's ability to sell power at market based rates in PJM, it could have an adverse effect on future off-system sales margins, results of operations and cash flows.

Our costs of compliance with environmental laws are significant and the cost of compliance with future environmental laws could harm our cash flow and profitability or cause some of our electric generating units to be uneconomical to maintain or operate. *(Applies to each registrant.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. Further, environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have advanced through the legislature. In April 2007 the U.S. Supreme Court determined that CO_2 is an "air pollutant" and that the Federal EPA has authority to regulate CO_2 emissions under the CAA. In July 2008 the Federal EPA issued an advance notice of proposed rulemaking (ANPR) that requests comments on a wide variety of issues in response to the U.S. Supreme Court's decision. The ANPR could lead to regulations limiting the emissions of CO_2 from our generating plants. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from our estimates. All of the costs are incremental to our current investment base and operating cost structure. In addition, any legal obligation that would require us to substantially reduce our emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices (in Ohio and Texas), without such recovery those costs could adversely affect future results of operations and cash flows, and possibly 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 results of operations could be adversely affected.

If Moody's or S&P were to downgrade the long-term rating of any of the securities of the registrants**,** particularly below investment grade, the borrowing costs of that registrant would increase, which would diminish its financial results. In addition, the registrant's potential pool of investors and funding sources could decrease. In the first quarter of 2008, Fitch downgraded the senior unsecured debt rating of PSO and SWEPCo to BBB+ with stable outlook. Moody's placed the senior unsecured debt rating of APCo, OPCo, SWEPCo and TCC on negative outlook in January 2008. Moody's assigns the following ratings to the senior unsecured debt of these companies: APCo Baa2, OPCo A3, SWEPCo Baa1 and TCC Baa2.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

In Ohio, we have limited ability to pass on our fuel costs to our customers. *(Applies to AEP, CSPCo and OPCo.)*

See risk factor above "Our request for rate recovery in Ohio may not be approved."

Risks Relating to State Restructuring

In Ohio, our future rates are uncertain. *(Applies to AEP, OPCo and CSPCo.)*

See risk factor above "Our request for rate recovery in Ohio may not be approved."

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended June 30, 2008 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
04/01/08 – 04/30/08	-	$ -	-	$ -
05/01/08 – 05/31/08	-	-	-	-
06/01/08 – 06/30/08	-	-	-	-

Item 4. Submission of Matters to a Vote of Security Holders

AEP

The annual meeting of shareholders was held in Shreveport, Louisiana, on April 22, 2008. The holders of shares entitled to vote at the meeting or their proxies cast votes at the meeting with respect to the following three matters, as indicated below:

1. Election of eleven directors to hold office until the next annual meeting and until their successors are duly elected. Each nominee for director received the votes of shareholders as follows:

	Number of Shares Voted For	Number of Shares Abstaining
E. R. Brooks	312,075,636	9,048,078
Donald M. Carlton	312,678,087	8,445,627
Ralph D. Crosby, Jr.	313,030,107	8,093,607
John P. DesBarres	298,693,953	22,429,761
Linda A. Goodspeed	312,709,888	8,413,826
Thomas E. Hoaglin	311,691,406	9,432,308
Lester A. Hudson, Jr.	312,928,042	8,195,672
Michael G. Morris	298,827,464	22,296,250
Lionel L. Nowell, III	311,500,225	9,623,489
Richard L. Sandor	308,409,310	12,714,404
Kathryn D. Sullivan	310,429,848	10,693,866

2. Ratification of the appointment of the firm of Deloitte & Touche LLP as the independent registered public accounting firm for 2008. The proposal was approved by a vote of the shareholders as follows:

Votes FOR	313,470,119
Votes AGAINST	4,721,969
Votes ABSTAINED	2,931,626

APCo

The annual meeting of stockholders was held on April 22, 2008 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 13,499,500 votes were cast FOR each of the following ten persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Stephen P. Smith
John B. Keane	Brian X. Tierney
Holly K. Koeppel	Susan Tomasky
Michael G. Morris	Dennis E. Welch

CSPCo

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 28, 2008, the following ten persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Stephen P. Smith
John B. Keane	Brian X. Tierney
Holly K. Koeppel	Susan Tomasky
Michael G. Morris	Dennis E. Welch

I&M

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated July 24, 2008, the following fifteen persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Marc E. Lewis
Kent D. Curry	Susanne M. Moorman Rowe
John E. Ehler	Michael G. Morris
Carl L. English	Helen J. Murray
Allen R. Glassburn	Robert P. Powers
JoAnn M. Grevenow	Brian X. Tierney
Patrick C. Hale	Susan Tomasky
Holly K. Koeppel	

OPCo

The annual meeting of shareholders was held on May 6, 2008 at 1 Riverside Plaza, Columbus, Ohio. At the meeting there were 27,952,473 votes were cast FOR each of the following ten persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Stephen P. Smith
John B. Keane	Brian X. Tierney
Holly K. Koeppel	Susan Tomasky
Michael G. Morris	Dennis E. Welch

PSO

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated July 24, 2008, the following ten persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Michael G. Morris
Carl L. English	Richard E. Munczinski
John B. Keane	Robert P. Powers
Holly K. Koeppel	Susan Tomasky
Venita McCellon-Allen	Dennis E. Welch

SWEPCo

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated July 24, 2008, the following ten persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Michael G. Morris
Carl L. English	Richard E. Munczinski
John B. Keane	Robert P. Powers
Holly K. Koeppel	Susan Tomasky
Venita McCellon-Allen	Dennis E. Welch

Item 5. <u>Other Information</u>

NONE

Item 6. <u>Exhibits</u>

PSO and SWEPCo

3(a) – Certificate of Amendment to Restated Certificate of Incorporation.

CSPCo and OPCo

3(b) – Amended Code of Regulations.

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: August 1, 2008