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

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **March 31, 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, Indiana Michigan Power Company and Public Service Company of Oklahoma meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the registrants at April 30, 2008
American Electric Power Company, Inc.	401,591,005 ($6.50 par value)
Appalachian Power Company	13,499,500 (no par value)
Columbus Southern Power Company	16,410,426 (no par value)
Indiana Michigan Power Company	1,400,000 (no par value)
Ohio Power Company	27,952,473 (no par value)
Public Service Company of Oklahoma	9,013,000 ($15 par value)
Southwestern Electric Power Company	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
March 31, 2008

	Page
Glossary of Terms	i
Forward-Looking Information	iv
Part I. FINANCIAL INFORMATION	
Items 1, 2 and 3 - Financial Statements, Management's Financial Discussion and Analysis and Quantitative and Qualitative Disclosures About Risk Management Activities:	
American Electric Power Company, Inc. and Subsidiary Companies:	
Management's Financial Discussion and Analysis of Results of Operations	A-1
Quantitative and Qualitative Disclosures About Risk Management Activities	A-18
Condensed Consolidated Financial Statements	A-24
Index to Condensed Notes to Condensed Consolidated Financial Statements	A-29
Appalachian Power Company and Subsidiaries:	
Management's Financial Discussion and Analysis	B-1
Quantitative and Qualitative Disclosures About Risk Management Activities	B-5
Condensed Consolidated Financial Statements	B-10
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	B-15
Columbus Southern Power Company and Subsidiaries:	
Management's Narrative Financial Discussion and Analysis	C-1
Quantitative and Qualitative Disclosures About Risk Management Activities	C-3
Condensed Consolidated Financial Statements	C-4
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	C-9
Indiana Michigan Power Company and Subsidiaries:	
Management's Narrative Financial Discussion and Analysis	D-1
Quantitative and Qualitative Disclosures About Risk Management Activities	D-3
Condensed Consolidated Financial Statements	D-4
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	D-9
Ohio Power Company Consolidated:	
Management's Financial Discussion and Analysis	E-1
Quantitative and Qualitative Disclosures About Risk Management Activities	E-5
Condensed Consolidated Financial Statements	E-9
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	E-14
Public Service Company of Oklahoma:	
Management's Narrative Financial Discussion and Analysis	F-1
Quantitative and Qualitative Disclosures About Risk Management Activities	F-3
Condensed Financial Statements	F-4
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	F-9
Southwestern Electric Power Company Consolidated:	
Management's Financial Discussion and Analysis	G-1
Quantitative and Qualitative Disclosures About Risk Management Activities	G-5
Condensed Consolidated Financial Statements	G-9
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	G-14

Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	H-1
Combined Management's Discussion and Analysis of Registrant Subsidiaries	I-1
Controls and Procedures	J-1
Part II. OTHER INFORMATION	
Item 1. Legal Proceedings	K-1
Item 1A. Risk Factors	K-1
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	K-2
Item 5. Other Information	K-2
Item 6. Exhibits:	K-2
Exhibit 12	
Exhibit 31(a)	
Exhibit 31(b)	
Exhibit 32(a)	
Exhibit 32(b)	
SIGNATURE	L-1

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System 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.
DOJ	United States Department of Justice.
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."
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."
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.
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.
PATH	Potomac Appalachian Transmission Highline, LLC and its subsidiaries, a joint venture with Allegheny Energy Inc. formed to own and operate electric transmission facilities in PJM.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
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 109	Statement of Financial Accounting Standards No. 109, “Accounting for Income Taxes.”
SFAS 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”
SFAS 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 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 potential for new legislation 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

Regulatory Activity

Updates to our significant regulatory activities in 2008 include:

- In February 2008, APCo and WPCo filed for an increase of approximately $156 million including a $135 million increase in the Expanded Net Energy Cost recovery mechanism, a $17 million increase in construction cost surcharges and $4 million of reliability expenditures, to all become effective July 2008.
- In February 2008, the FERC approved a PATH request for a transmission formula rate and ordered that the formula rates go into effect in March 2008. Settlement negotiations began and motions for rehearing were filed by intervening parties in March 2008. PATH requested an incentive return of 14.3% on its equity investment using a 50/50 debt to equity ratio, the recovery of deferred pre-operating, pre-construction costs and the recovery of construction financing costs through the inclusion of CWIP in rate base with a true-up to actual for these costs.
- In March 2008, the OCC approved a settlement for recovery of 2007 Oklahoma ice storm costs, subject to an audit of December ice storm costs to be filed in July 2008. As a result, PSO recorded an $81 million regulatory asset for actual 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.
- In March 2008, PSO and all other parties signed a settlement agreement that provides for recovery of $11 million of pre-construction costs related to PSO's Red Rock Generating Facility. PSO filed the settlement with the OCC for approval. A hearing on the settlement is scheduled for May 2008. As a result of the settlement, PSO wrote-off $10 million of its remaining unrecoverable deferred pre-construction costs/cancellation fees in the first quarter of 2008.
- In March 2008, the WVPSC granted APCo a Certificate of Public Convenience and Necessity and recovery of pre-construction and construction financing costs related to the planned construction of the IGCC plant in West Virginia. Various intervenors filed petitions with the WVPSC to reconsider the order. In April 2008, the Virginia SCC denied APCo's request for approval of the plant and to recover pre-construction and construction financing costs. In April 2008, APCo filed a petition for reconsideration in Virginia.
- In March 2008, the LPSC approved the application to construct the Turk Plant. In January 2008, a Texas ALJ recommended that SWEPCo's application be denied and subsequently, in March 2008, the PUCT voted to reopen the record and conduct additional hearings. SWEPCo expects a decision from the PUCT in the last half of 2008.
- In March 2008, APCo filed a notice with the Virginia SCC that it plans to file a general base rate case no sooner than May 2008. APCo will also file for recovery of $46 million of incremental E&R costs.
- In April 2008, the LPSC approved a settlement agreement between SWEPCo and the LPSC staff that established a formula rate plan 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%.
- In April 2008, the Ohio legislature passed legislation which allows utilities to set prices by filing an Electric Security Plan along with the ability to simultaneously file a Market Rate Option. The PUCO would have authority to approve or modify the utility's request to set prices. Both alternatives would involve earnings tests monitored by the PUCO. The legislation still must be signed by the Ohio governor and will become law 90 days after the Governor's signature.

Fuel Costs

We expected coal costs to increase by 13% in 2008, but due to escalating domestic prices and increased needs, our current estimate is in the range of a 14% to 18% increase. 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 very volatile. Going forward, we have some 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, the current pending legislation in Ohio includes a fuel cost recovery mechanism. Fuel cost adjustment rate clauses in our other jurisdictions will help offset future negative impacts of fuel price increases on our gross margins.

RESULTS OF OPERATIONS

Segments

Our principal operating business segments and their related business activities are as follows:

Utility Operations

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

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.

Generation and Marketing

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

The table below presents our consolidated Net Income by segment for the three months ended March 31, 2008 and 2007.

	Three Months Ended March 31, 2008	2007
	(in millions)	
Utility Operations	$ 410	$ 253
MEMCO Operations	7	15
Generation and Marketing	1	(1)
All Other (a)	155	4
Net Income	$ 573	$ 271

(a) All Other includes:

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

AEP Consolidated

First Quarter of 2008 Compared to First Quarter of 2007

Net Income in 2008 increased $302 million compared to 2007 primarily due to 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 and an increase in Utility Operations segment earnings of $157 million. The increase in Utility Operations segment earnings primarily relates to lower operation and maintenance expenses as a result of a favorable Oklahoma ice storm settlement and rate increases implemented since the first quarter of 2007 in Ohio, Virginia, West Virginia, Texas and Oklahoma.

Average basic shares outstanding increased to 401 million in 2008 from 397 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 March 31, 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.

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(in millions)	
Revenues	$ 3,294	$ 3,033
Fuel and Purchased Power	1,213	1,119
Gross Margin	2,081	1,914
Depreciation and Amortization	355	383
Other Operating Expenses	941	991
Operating Income	785	540
Other Income, Net	42	18
Interest Charges and Preferred Stock Dividend Requirements	210	179
Income Tax Expense	207	126
Net Income	$ 410	$ 253

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three Months Ended March 31, 2008 and 2007

	2008	2007
Energy Summary	(in millions of KWH)	
Retail:		
Residential	14,500	14,139
Commercial	9,547	9,359
Industrial	14,350	13,565
Miscellaneous	609	614
Total Retail	39,006	37,677
Wholesale	11,666	8,778
Texas Wires – Energy Delivered to Customers Served by TNC and TCC in ERCOT	5,823	5,831
Total KWHs	56,495	52,286

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on results of operations. In general, degree day changes in our eastern region have a larger effect on results of operations than changes in our western region due to the relative size of the two regions and the associated number of customers within each. Cooling degree days and heating degree days in our service territory for the three months ended March 31, 2008 and 2007 were as follows:

	2008	2007
Weather Summary	**(in degree days)**	
Eastern Region		
Actual – Heating (a)	1,824	1,816
Normal – Heating (b)	1,767	1,792
Actual – Cooling (c)	-	14
Normal – Cooling (b)	3	3
Western Region (d)		
Actual – Heating (a)	949	902
Normal – Heating (b)	931	959
Actual – Cooling (c)	26	56
Normal – Cooling (b)	20	18

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

First Quarter of 2008 Compared to First Quarter of 2007

Reconciliation of First Quarter of 2007 to First Quarter of 2008
Net Income from Utility Operations
(in millions)

First Quarter of 2007		$	253
Changes in Gross Margin:			
Retail Margins	114		
Off-system Sales	40		
Transmission Revenues	8		
Other Revenues	5		
Total Change in Gross Margin			167
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	81		
Gain on Dispositions of Assets, Net	(21)		
Depreciation and Amortization	28		
Taxes Other Than Income Taxes	(10)		
Carrying Costs Income	10		
Interest Income	11		
Other Income, Net	3		
Interest and Other Charges	(31)		
Total Change in Operating Expenses and Other			71
Income Tax Expense			(81)
First Quarter of 2008		$	410

Net Income from Utility Operations increased $157 million to $410 million in 2008. The key driver of the increase was a $167 million increase in Gross Margin and a $71 million decrease in Operating Expenses and Other offset by an $81 million increase in Income Tax Expense.

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

- Retail Margins increased $114 million primarily due to the following:
  - A $44 million increase related to RSP rate increases implemented in our Ohio jurisdictions with PUCO approval, a $14 million increase related to recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $9 million increase in base rates in Texas and an $8 million increase in base rates in Oklahoma.
  - A $58 million increase related to an OPCo coal contract amendment which reduced future deliveries to OPCo in exchange for consideration received.
  - A $23 million increase related to increased residential and commercial usage and customer growth.
  - A $21 million increase related to increased usage by Ormet, an industrial customer in Ohio. See "Ormet" section of Note 3.

  These increases were partially offset by:
  - A $55 million decrease related to increased fuel, consumable and allowance costs in Ohio.
- 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.

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

- Other Operation and Maintenance expenses decreased $81 million primarily due to a deferral of storm restoration costs of $80 million in Oklahoma as a result of a rate settlement to recover 2007 storm restoration costs partially offset by an increase in generation expenses from base operations and the write-off of $10 million of unrecoverable pre-construction costs for PSO's canceled Red Rock Generating Facility.
- Gain on Disposition of Assets, Net decreased $21 million 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, Virginia, Oklahoma and Texas and lower Ohio regulatory asset amortization, partially offset by higher depreciable property balances.
- Taxes Other Than Income Taxes increased $10 million primarily due to higher property taxes related to property additions.
- 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 $31 million primarily due to additional debt issued in 2007 and higher interest rates on variable rate debt.
- Income Tax Expense increased $81 million due to an increase in pretax income.

MEMCO Operations

First Quarter of 2008 Compared to First Quarter of 2007

Net Income from our MEMCO Operations segment decreased from $15 million in 2007 to $7 million in 2008 primarily due to high water conditions and reduced northbound loadings. Operating costs were higher due to the sustained high water conditions on all major rivers and existing river regulations resulting in reduced tow sizes and restricted operating hours which increased fuel consumption. Northbound loadings continue to be depressed as a result of reduced imports through the Gulf.

Generation and Marketing

First Quarter of 2008 Compared to First Quarter of 2007

Net Income from our Generation and Marketing segment increased to $1 million in 2008 from a loss of $1 million in 2007 primarily due to an increase in income from wind farm operations.

All Other

First Quarter of 2008 Compared to First Quarter of 2007

Net Income from All Other increased from $4 million in 2007 to $155 million in 2008. 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 ($163 million, net of tax). 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 $163 million primarily due to an increase in pretax book income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	March 31, 2008		December 31, 2007	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 15,636	58.8%	$ 14,994	58.1%
Short-term Debt	409	1.5	660	2.6
Total Debt	16,045	60.3	15,654	60.7
Common Equity	10,489	39.5	10,079	39.1
Preferred Stock	61	0.2	61	0.2
Total Debt and Equity Capitalization	$ 26,595	100.0%	$ 25,794	100.0%

Our ratio of debt to total capital decreased from 60.7% to 60.3% in 2008 due to our 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 or 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 March 31, 2008, we had $1.4 billion outstanding of tax-exempt long-term debt sold at auction rates that reset every 7, 28 or 35 days. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation, Financial Guaranty Insurance Co., MBIA Insurance Corporation and XL Capital Assurance Inc. 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. During the first quarter of 2008, we reduced our outstanding auction rate securities by redeeming or repurchasing $95 million of such debt securities. In April 2008, we converted, refunded or provided notice to convert or refund $940 million of our outstanding auction rate securities. We plan to continue this conversion and refunding process for the remaining $471 million to other permitted modes, including term-put and fixed-rate structures through the third quarter of 2008. The conversions will likely result in higher interest charges compared to prior year but lower than the failed auction rates for this tax-exempt long-term debt.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At March 31, 2008, our available liquidity was approximately $2.7 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
Total		3,000	
Cash and Cash Equivalents		155	
Total Liquidity Sources		3,155	
Less: AEP Commercial Paper Outstanding		409	
Letters of Credit Drawn		57	
Net Available Liquidity	$	2,689	

The facilities are structured as two $1.5 billion credit facilities of which $300 million may be issued under each credit facility as letters of credit. 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 an additional $650 million 3-year credit agreement and another $350 million 364-day credit agreement.

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of March 31, 2008, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during the first quarter of 2008 was $1.1 billion. The weighted-average interest rate of our commercial paper during the first quarter of 2008 was 3.66%.

Investments in Auction-Rate Securities

As of March 31, 2008, we had $39 million invested in auction-rate securities. During the first quarter of 2008, we transferred $135 million of these securities from fair value hierarchy level 2 to level 3 due to the deterioration of liquidity in the auction-rate security market and subsequently sold $96 million of such securities at par. Issuers have given us notice that they will call a majority of our remaining investments in auction-rate securities at par. Therefore, based on this fact and our review of the underlying credit quality of these securities, we have not recorded an impairment of these investments.

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 March 31, 2008, this contractually-defined percentage was 54.9%. Nonperformance of these covenants could result in an event of default under these credit agreements. At March 31, 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.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At March 31, 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 April 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 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. Moody's affirmed its stable outlook for AEP and our other subsidiaries. Fitch downgraded PSO and SWEPCo from A- to BBB+ for senior unsecured debt. 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.

	Three Months Ended March 31,	
	2008	2007
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 178	$ 301
Net Cash Flows from Operating Activities	628	351
Net Cash Flows Used for Investing Activities	(894)	(628)
Net Cash Flows from Financing Activities	243	235
Net Decrease in Cash and Cash Equivalents	(23)	(42)
Cash and Cash Equivalents at End of Period	$ 155	$ 259

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Three Months Ended March 31, 2008	2007
	(in millions)	
Net Income	$ 573	$ 271
Depreciation and Amortization	363	391
Other	(308)	(311)
Net Cash Flows from Operating Activities	$ 628	$ 351

Net Cash Flows from Operating Activities increased in 2008 primarily due to increased income reflecting an improvement in gross margins on energy sales and the TEM settlement.

Net Cash Flows from Operating Activities were $628 million in 2008 consisting primarily of Net Income of $573 million and $363 million of noncash depreciation and amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items resulted in lower cash from operations due to payment of items accrued at December 31, 2007.

Net Cash Flows from Operating Activities were $351 million in 2007 consisting primarily of Net Income of $271 million and $391 million of noncash depreciation and amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items resulted in lower cash from operations due to payment of items accrued at December 31, 2006.

Investing Activities

	Three Months Ended March 31, 2008	2007
	(in millions)	
Construction Expenditures	$ (778)	$ (907)
Proceeds from Sales of Assets	18	68
Other	(134)	211
Net Cash Flows Used for Investing Activities	$ (894)	$ (628)

Net Cash Flows Used for Investing Activities were $894 million in 2008 and $628 million in 2007 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.

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

We forecast approximately $3 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

	Three Months Ended March 31, 2008	2007
	(in millions)	
Issuance of Common Stock	$ 45	$ 54
Issuance/Retirement of Debt, Net	376	355
Dividends Paid on Common Stock	(165)	(155)
Other	(13)	(19)
Net Cash Flows from Financing Activities	$ 243	$ 235

Net Cash Flows from Financing Activities in 2008 were $243 million primarily due to the issuance of $315 million of junior subordinated debentures and $500 million of senior unsecured notes partially offset by the retirement of $95 million of pollution control bonds, $52 million of senior unsecured notes and $34 million of mortgage notes and the reduction of our short-term commercial paper outstanding by $251 million. 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 $235 million primarily due to $150 million of short-term commercial paper borrowings under our credit facilities and issuing $250 million of debt securities.

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:

	March 31, 2008	December 31, 2007
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 502	$ 507
Rockport Plant Unit 2 Future Minimum Lease Payments	2,216	2,216
Railcars Maximum Potential Loss From Lease Agreement	30	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 discussed in “Cash Flow” 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 Restructuring

The current Ohio restructuring legislation permits CSPCo and OPCo to implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. The RSP plans include generation rates which are between PUCO approved rates and higher market rates. In April 2008, the Ohio legislature passed legislation which allows utilities to set prices by filing an Electric Security Plan along with the ability to simultaneously file a Market Rate Option. The PUCO would have authority to approve or modify the utility's request to set prices. Both alternatives would involve earnings tests monitored by the PUCO. The legislation still must be signed by the Ohio governor and will become law 90 days after the governor's signature. Management is analyzing the financial statement implications of the pending legislation on CSPCo's and OPCo's generation supply business, more specifically, whether the fuel management operations of CSPCo and OPCo meet the criteria for application of SFAS 71. The financial statement impact of the pending legislation will not be known until the PUCO acts on specific proposals made by CSPCo and OPCo. Management expects a PUCO decision in the fourth quarter of 2008.

Texas Restructuring

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 is also refunding its net other true-up items of $375 million through 2008 via a CTC credit rate rider. 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. However, the District Court did not rule that the carrying cost rate was inappropriate. If the PUCT reevaluates the carrying cost rate on remand and reduces the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition.

The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. If upheld on appeal, this ruling could have a materially favorable effect on TCC's results of operations and cash flows.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. Management cannot predict the outcome of these court proceedings. 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, or if TCC has a tax normalization violation, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

New Generation

AEP is in various stages of construction of the following generation facilities. Certain plants are pending regulatory approval:

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	$ 58		$ -	Gas	Simple-cycle	170		2008
PSO	Riverside		Oklahoma	59		57	Gas	Simple-cycle	170		2008
AEGCo	Dresden	(d)	Ohio	305	(d)	101	Gas	Combined-cycle	580		2010
SWEPCo	Stall		Louisiana	378		76	Gas	Combined-cycle	500		2010
SWEPCo	Turk	(e)	Arkansas	1,522	(e)	313	Coal	Ultra-supercritical	600	(e)	2012
APCo	Mountaineer		West Virginia	2,230		-	Coal	IGCC	629		2012
CSPCo/OPCo	Great Bend		Ohio	2,700	(f)	-	Coal	IGCC	629		2017

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) 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.
(e) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals. See “Turk Plant” section below.
(f) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO. See “Ohio IGCC Plant” section of Note 3.

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 facility. 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. As of March 31, 2008, including the joint owners’ share, SWEPCo capitalized approximately $313 million of expenditures and has significant contractual construction commitments for an additional $838 million. As of March 31, 2008, if the plant were to be cancelled, then cancellation fees of $67 million would terminate these construction commitments.

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. SWEPCo is still awaiting permit approvals from the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers. Both permits are expected to be received by the third quarter of 2008. The PUCT held hearings in October 2007. In January 2008, a Texas ALJ issued a report, which concluded that SWEPCo failed to prove there was a need for the plant. The Texas ALJ recommended that SWEPCo’s application be denied. The PUCT has voted to reopen the record and conduct additional hearings. SWEPCo expects a decision from the PUCT in the last half of 2008. In March 2008, the LPSC approved the certificate to construct the Turk Plant. If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. If SWEPCo cannot recover its costs, it could have an adverse effect on future results of operations, cash flows and possibly financial condition.

APCo's IGCC Plant

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, WV. 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 July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover pre-construction and future construction financing costs associated with the IGCC plant.

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.

The Virginia SCC issued an order in April 2008 denying APCo's requests on the basis of their belief that the estimated cost may be significantly understated. The Virginia SCC also expressed concern that the $2.2 billion estimated cost of the IGCC plant did not include a retrofitting of carbon capture and sequestration facilities. In April 2008, APCo filed a petition for reconsideration in Virginia. If necessary, APCo will seek recovery of its prudently incurred deferred pre-construction costs.

Through March 31, 2008, APCo deferred for future recovery pre-construction IGCC costs of $16 million. If these deferred costs are not recoverable, 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. Litigation continues against two plants CSPCo jointly-owns with Duke and DP&L, which they operate. We are unable to predict the outcome of these cases. 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 monitoring 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 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 include 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 FASB Staff Position (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 $10 million (net of tax of $6 million) 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 September 15, 2007. The adoption of this standard had an immaterial impact on our financial statements.

In April 2007, the FASB issued FASB Staff Position 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 "FASB Staff Position 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 March 31, 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 March 31, 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	$ 411	$ 215	$ 95	$ 721	$ 25	$ (48)	$ 698
Noncurrent Assets	199	101	71	371	8	(37)	342
Total Assets	610	316	166	1,092	33	(85)	1,040
Current Liabilities	(365)	(231)	(96)	(692)	(82)	94	(680)
Noncurrent Liabilities	(104)	(43)	(77)	(224)	(3)	6	(221)
Total Liabilities	(469)	(274)	(173)	(916)	(85)	100	(901)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 141	$ 42	$ (7)	$ 176	$ (52)	15	$ 139

MTM Risk Management Contract Net Assets (Liabilities) Three Months Ended March 31, 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	(28)	1	-	(27)
Fair Value of New Contracts at Inception When Entered During the Period (a)	1	-	-	1
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	4	2	1	7
Changes in Fair Value Due to Market Fluctuations During the Period (c)	3	(4)	-	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	5	-	-	5
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2008	$ 141	$ 42	$ (7)	$ 176
Net Cash Flow and Fair Value Hedge Contracts				(52)
Collateral Deposits				15
Ending Net Risk Management Assets at March 31, 2008				$ 139

(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 March 31, 2008 (in millions)

	Remainder 2008	2009	2010	2011	2012	After 2012 (f)	Total
Utility Operations:							
Level 1 (a)	$ (6)	$ (3)	$ -	$ -	$ -	$ -	(9)
Level 2 (b)	28	43	29	2	1	-	103
Level 3 (c)	-	4	(7)	-	-	-	(3)
Total	22	44	22	2	1	-	91
Generation and Marketing:							
Level 1 (a)	(21)	5	-	-	-	-	(16)
Level 2 (b)	4	(6)	2	3	3	-	6
Level 3 (c)	-	1	9	9	8	25	52
Total	(17)	-	11	12	11	25	42
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)	(27)	2	-	-	-	-	(25)
Level 2 (b)	31	33	27	7	4	-	102
Level 3 (c) (d)	-	5	2	9	8	25	49
Total	$ 4	$ 40	$ 29	$ 16	$ 12	$ 25	$ 126
Dedesignated Risk Management Contracts (e)	11	14	14	6	5	-	50
Total MTM Risk Management Contract Net Assets	$ 15	$ 54	$ 43	$ 22	$ 17	$ 25	$ 176

(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 $25 million in individual periods beyond 2012. $8 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 $3 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 the Liquid Portion of Risk Management Contracts
As of March 31, 2008

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	21
	Swaps	Gas East, Mid-Continent, Gulf Coast, Texas	21
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	Power East – PJM	36
	Physical Forwards	Power East – Cinergy	45
	Physical Forwards	Power East – PJM West	57
	Physical Forwards	Power East – AEP Dayton (PJM)	57
	Physical Forwards	Power East – ERCOT	33
	Physical Forwards	Power East – Entergy	33
	Physical Forwards	Power West – PV, NP15, SP15, MidC, Mead	57
	Peak Power Volatility (Options)	Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	45
Coal	Physical Forwards	PRB, NYMEX, CSX	33

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 transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedge strategies. 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 March 31, 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
Three Months Ended March 31, 2008
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2007	$ (1)	$ (25)	$ (26)
Changes in Fair Value	(26)	(6)	(32)
Reclassifications from AOCI for Cash Flow Hedges Settled	2	-	2
Ending Balance in AOCI, March 31, 2008	$ (25)	$ (31)	$ (56)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ (31)	$ (6)	$ (37)

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. Only after an entity has met our internal credit rating criteria will we extend unsecured credit. We use Moody's Investors Service, Standard & Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. We use our analysis, in conjunction with the rating agencies' information, to determine appropriate risk parameters. We also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of March 31, 2008, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 11.8%, expressed in terms of net MTM assets and net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of March 31, 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	$ 659	$ 75	$ 584	1	$ 93
Split Rating	15	-	15	4	14
Noninvestment Grade	100	47	53	1	48
No External Ratings:					
Internal Investment Grade	125	-	125	3	95
Internal Noninvestment Grade	47	3	44	2	42
Total as of March 31, 2008	$ 946	$ 125	$ 821	11	$ 292
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 March 31, 2008

	Remainder 2008	2009	2010
Estimated Plant Output Hedged	89%	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 March 31, 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

Three Months Ended March 31, 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 $36 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2008 and 2007
(in millions, except per-share amounts and shares outstanding)
(Unaudited)

	2008	2007
REVENUES		
Utility Operations	$ 3,010	$ 2,886
Other	457	283
TOTAL	3,467	3,169
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	980	886
Purchased Energy for Resale	263	246
Other Operation and Maintenance	878	938
Gain on Disposition of Assets, Net	(3)	(23)
Asset Impairments and Other Related Items	(255)	-
Depreciation and Amortization	363	391
Taxes Other Than Income Taxes	198	186
TOTAL	2,424	2,624
OPERATING INCOME	1,043	545
Interest and Investment Income	16	23
Carrying Costs Income	17	8
Allowance For Equity Funds Used During Construction	10	8
INTEREST AND OTHER CHARGES		
Interest Expense	220	186
Preferred Stock Dividend Requirements of Subsidiaries	1	1
TOTAL	221	187
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	865	397
Income Tax Expense	293	130
Minority Interest Expense	1	1
Equity Earnings of Unconsolidated Subsidiaries	2	5
NET INCOME	$ 573	$ 271
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	400,797,993	397,314,642
BASIC EARNINGS PER SHARE	$ 1.43	$ 0.68
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	402,072,098	398,552,113
DILUTED EARNINGS PER SHARE	$ 1.43	$ 0.68
CASH DIVIDENDS PAID PER SHARE	$ 0.41	$ 0.39

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 155	$ 178
Other Temporary Investments	339	365
Accounts Receivable:		
Customers	662	730
Accrued Unbilled Revenues	343	379
Miscellaneous	88	60
Allowance for Uncollectible Accounts	(43)	(52)
Total Accounts Receivable	1,050	1,117
Fuel, Materials and Supplies	947	967
Risk Management Assets	698	271
Margin Deposits	51	47
Prepayments and Other	121	81
TOTAL	3,361	3,026
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	20,502	20,233
Transmission	7,498	7,392
Distribution	12,217	12,056
Other (including coal mining and nuclear fuel)	3,472	3,445
Construction Work in Progress	3,001	3,019
Total	46,690	46,145
Accumulated Depreciation and Amortization	16,319	16,275
TOTAL - NET	30,371	29,870
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,224	2,199
Securitized Transition Assets	2,109	2,108
Spent Nuclear Fuel and Decommissioning Trusts	1,324	1,347
Goodwill	76	76
Long-term Risk Management Assets	342	319
Employee Benefits and Pension Assets	484	486
Deferred Charges and Other	1,026	888
TOTAL	7,585	7,423
TOTAL ASSETS	$ 41,317	$ 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
March 31, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,176	$ 1,324
Short-term Debt	409	660
Long-term Debt Due Within One Year	931	792
Risk Management Liabilities	680	240
Customer Deposits	308	301
Accrued Taxes	743	601
Accrued Interest	196	235
Other	729	1,008
TOTAL	5,172	5,161
NONCURRENT LIABILITIES		
Long-term Debt	14,705	14,202
Long-term Risk Management Liabilities	221	188
Deferred Income Taxes	4,854	4,730
Regulatory Liabilities and Deferred Investment Tax Credits	2,883	2,952
Asset Retirement Obligations	1,071	1,075
Employee Benefits and Pension Obligations	703	712
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	136	139
Deferred Credits and Other	1,022	1,020
TOTAL	25,595	25,018
TOTAL LIABILITIES	30,767	30,179
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50 Per Share:		

	2008	2007
Shares Authorized	600,000,000	600,000,000
Shares Issued	423,005,402	421,926,696

	2008	2007
(21,499,992 shares were held in treasury at March 31, 2008 and December 31, 2007, respectively)	2,750	2,743
Paid-in Capital	4,391	4,352
Retained Earnings	3,535	3,138
Accumulated Other Comprehensive Income (Loss)	(187)	(154)
TOTAL	10,489	10,079
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 41,317	$ 40,319

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2008 and 2007
(in millions)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 573	$ 271
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	363	391
Deferred Income Taxes	111	5
Deferred Investment Tax Credits	(5)	(6)
Carrying Costs Income	(17)	(8)
Allowance for Equity Funds Used During Construction	(10)	(8)
Mark-to-Market of Risk Management Contracts	(26)	21
Amortization of Nuclear Fuel	22	16
Deferred Property Taxes	(64)	(67)
Fuel Over/Under-Recovery, Net	(57)	(62)
Gain on Sales of Assets and Equity Investments, Net	(3)	(23)
Change in Other Noncurrent Assets	(119)	52
Change in Other Noncurrent Liabilities	(66)	16
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	61	(29)
Fuel, Materials and Supplies	20	(3)
Margin Deposits	(4)	19
Accounts Payable	(7)	(31)
Customer Deposits	6	(8)
Accrued Taxes	149	32
Accrued Interest	(44)	25
Other Current Assets	(21)	(40)
Other Current Liabilities	(234)	(212)
Net Cash Flows from Operating Activities	628	351
INVESTING ACTIVITIES		
Construction Expenditures	(778)	(907)
Change in Other Temporary Investments, Net	(26)	(20)
Purchases of Investment Securities	(491)	(3,693)
Sales of Investment Securities	500	3,929
Proceeds from Sales of Assets	18	68
Other	(117)	(5)
Net Cash Flows Used for Investing Activities	(894)	(628)
FINANCING ACTIVITIES		
Issuance of Common Stock	45	54
Change in Short-term Debt, Net	(251)	157
Issuance of Long-term Debt	916	247
Retirement of Long-term Debt	(289)	(49)
Dividends Paid on Common Stock	(165)	(155)
Other	(13)	(19)
Net Cash Flows from Financing Activities	243	235
Net Decrease in Cash and Cash Equivalents	(23)	(42)
Cash and Cash Equivalents at Beginning of Period	178	301
Cash and Cash Equivalents at End of Period	$ 155	$ 259
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 252	$ 152
Net Cash Paid for Income Taxes	36	66
Noncash Acquisitions Under Capital Leases	19	11
Noncash Acquisition of Land/Mineral Rights	42	-
Construction Expenditures Included in Accounts Payable at March 31,	284	323

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 Three Months Ended March 31, 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	2	10	44			54
Common Stock Dividends				(155)		(155)
Other			5			5
TOTAL						9,299
COMPREHENSIVE INCOME						
Other Comprehensive Loss, Net of Tax:						
Cash Flow Hedges, Net of Tax of $12					(22)	(22)
Securities Available for Sale, Net of Tax of $4					(8)	(8)
NET INCOME				271		271
TOTAL COMPREHENSIVE INCOME						241
MARCH 31, 2007	420	$ 2,728	$ 4,270	$ 2,795	$ (253)	$ 9,540
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	1	7	38			45
Common Stock Dividends				(165)		(165)
Other			1			1
TOTAL						9,949
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $17					(30)	(30)
Securities Available for Sale, Net of Tax of $3					(6)	(6)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $2					3	3
NET INCOME				573		573
TOTAL COMPREHENSIVE INCOME						540
MARCH 31, 2008	423	$ 2,750	$ 4,391	$ 3,535	$ (187)	$ 10,489

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
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Acquisitions and Dispositions
6. Benefit Plans
7. Business Segments
8. Income Taxes
9. Financing Activities

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 months ended March 31, 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 (EPS)

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

	Three Months Ended March 31,			
	2008		2007	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to Common Stock	$ 573		$ 271	
Average Number of Basic Shares Outstanding	400.8	$ 1.43	397.3	$ 0.68
Average Dilutive Effect of:				
Performance Share Units	0.9	-	0.6	-
Stock Options	0.2	-	0.5	-
Restricted Stock Units	0.1	-	0.1	-
Restricted Shares	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	402.1	$ 1.43	398.6	$ 0.68

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 117,050 shares of common stock were outstanding at March 31, 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 March 31, 2008	2007
	(in millions)	
AEP Consolidated Revenues – Utility Operations:		
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% owned)	$ (13)	$ -
AEP Consolidated Revenues – Other:		
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	9	9
AEP Consolidated Expenses – Purchased Energy for Resale:		
Ohio Valley Electric Corporation (43.47% Owned)	63	49
Sweeny Cogeneration Limited Partnership (a)	-	30

(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 "FASB Staff Position FIN 39-1 Amendment of FASB Interpretation No. 39" section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on our previously reported results of operations or changes in shareholders' equity.

2. 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 include 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 FASB Staff Position (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).

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. 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 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 March 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 109	$ -	$ -	$ 46	$ 155
Other Temporary Investments:					
Cash and Cash Equivalents (b)	$ 147	$ -	$ -	$ 32	$ 179
Debt Securities	120	-	22	-	142
Equity Securities	18	-	-	-	18
Total Other Temporary Investments	$ 285	$ -	$ 22	$ 32	$ 339
Risk Management Assets:					
Risk Management Contracts (c)	$ 206	$ 3,201	$ 116	$ (2,566)	$ 957
Cash Flow and Fair Value Hedges (c)	-	46	-	(13)	33
Dedesignated Risk Management Contracts (d)	-	-	-	50	50
Total Risk Management Assets	$ 206	$ 3,247	$ 116	$ (2,529)	$ 1,040
Spent Nuclear Fuel and Decommissioning Trusts:					
Cash and Cash Equivalents (e)	$ -	$ 13	$ -	$ 10	$ 23
Debt Securities	343	492	-	-	835
Equity Securities	466	-	-	-	466
Total Spent Nuclear Fuel and Decommissioning Trusts	$ 809	$ 505	$ -	$ 10	$ 1,324
Investments in Debt Securities – Noncurrent (f)	$ -	$ -	$ 17	$ -	$ 17
Total Assets	$ 1,409	$ 3,752	$ 155	$ (2,441)	$ 2,875
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (c)	$ 231	$ 3,099	$ 67	$ (2,581)	$ 816
Cash Flow and Fair Value Hedges (c)	5	93	-	(13)	85
Total Risk Management Liabilities	$ 236	$ 3,192	$ 67	$ (2,594)	$ 901
Long-term Debt (g)	$ -	$ 50	$ -	$ -	$ 50
Total Liabilities	$ 236	$ 3,242	$ 67	$ (2,594)	$ 951

(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 FASB Staff Position 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 deposits-in-transit and accrued interest receivables to/from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(f) "Investments in Debt Securities – Noncurrent" represent investments in auction-rate securities where redemption has not been publicly noticed by the issuer and are included in Deferred Charges and Other on the accompanying Condensed Consolidated Balance Sheets.
(g) Amount represents the fair valued portion of long-term debt designated as a fair value hedge.

The following table sets forth a reconciliation primarily of changes in the fair value of net trading derivatives and other investments classified as level 3 in the fair value hierarchy:

	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)	(3)	-	-
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	5	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements	-	(96)	-
Transfers in and/or out of Level 3 (b)	(5)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	3	-	-
Balance as of March 31, 2008	$ 49	$ 22	$ 17

(a) Included in revenues on our Condensed Consolidated Statement of Income for the Three Months Ended March 31, 2008.
(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.

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 $10 million (net of tax of $6 million) 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.

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 September 15, 2007. The adoption of this standard had an immaterial impact on our financial statements.

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 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 March 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 March 31, 2008 balance sheet, we netted $85 million of cash collateral received from third parties against short-term and long-term risk management assets and $100 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, liabilities and equity, emission allowances, earnings per share calculations, leases, insurance, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

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 Restructuring

The current Ohio restructuring legislation permits CSPCo and OPCo to implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. The RSP plans include generation rates which are between PUCO approved rates and higher market rates. In April 2008, the Ohio legislature passed legislation which allows utilities to set prices by filing an Electric Security Plan along with the ability to simultaneously file a Market Rate Option. The PUCO would have authority to approve or modify the utility's request to set prices. Both alternatives would involve earnings tests monitored by the PUCO. The legislation still must be signed by the Ohio governor and will become law 90 days after the governor's signature. Management is analyzing the financial statement implications of the pending legislation on CSPCo's and OPCo's generation supply business, more specifically, whether the fuel management operations of CSPCo and OPCo meet the criteria for application of SFAS 71. The financial statement impact of the pending legislation will not be known until the PUCO acts on specific proposals made by CSPCo and OPCo. Management expects a PUCO decision in the fourth quarter of 2008.

2008 Generation Rider and Transmission Rider Rate Settlement

On January 30, 2008, the PUCO approved under the RSPs a settlement agreement, among CSPCo, OPCo and other parties, related to an additional average 4% generation rate increase and transmission cost recovery rider ("TCRR") adjustments to recover additional governmentally-mandated costs including increased 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 increased PJM costs 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 adjust billings to reflect actual costs including carrying costs. 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 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 matter.

Customer Choice Deferrals

CSPCo's and OPCo's restructuring settlement agreement, approved by the PUCO in 2000, allows CSPCo and OPCo to establish regulatory assets for customer choice implementation costs and related carrying costs in excess of $20 million each for recovery in the next general base rate filing for the distribution business. Through March 31, 2008, CSPCo and OPCo incurred $54 million and $55 million, respectively, of such costs and established regulatory assets for future recovery of $27 million each, net of equity carrying costs of $7 million for CSPCo and $8 million for OPCo. Management believes that these costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates. However, failure of the PUCO to ultimately approve recovery of such costs would have an adverse effect on results of operations and cash flows.

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 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, traditional rate making procedures would apply. 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 from approved orders of the PUCO.

Recent estimates of the cost to build the proposed IGCC plant are approximately $2.7 billion. In light of the Ohio Supreme Court's decision, CSPCo and OPCo will not start construction of the IGCC plant and will await the outcome of the ongoing legislative process in Ohio to determine if it provides sufficient assurance of cost recovery to warrant commencing construction.

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. The recovery will be accomplished by 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 $2 million of this regulatory liability to income for the quarter ended March 31, 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. If the PUCO approves a market price for 2008 below the 2007 price, it could have an adverse effect on future results of operations and cash flows. 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 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 is also refunding its net other true-up items of $375 million through 2008 via a CTC credit rate rider. 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.
- The 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. However, the District Court did not rule that the carrying cost rate was inappropriate. If the PUCT reevaluates the carrying cost rate on remand and reduces the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition.

The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. If upheld on appeal, this ruling could have a materially favorable effect on TCC's results of operations and cash flows.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. Management cannot predict the outcome of these court proceedings. 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, or if TCC has a tax normalization violation, 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 requested that the Texas Court of Appeals remand the tax normalization issue for the PUCT to consider additional evidence. 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.

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 these amounts, which will have a favorable effect on future results of operations and cash flows as the ADITC and EDFIT are recorded in income due to the sale of the generating plants.

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 March 31, 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 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 in the third quarter of 2007 of $16 million and $9 million, respectively.

The PUCT or another interested party could file a complaint at the FERC to challenge the allocation of off-system sales margins under the FERC-approved allocation agreement. 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 TNC misapplied its allocation under the FERC-approved agreement. 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 agreement 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 for the expected refund to be received from the REPs. 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.

<u>Virginia Rate Matters</u>

Virginia Base Rate Filing

In March 2008, APCo filed a notice with the Virginia SCC that it plans to file a general base rate case no sooner than May 2008. The rate case will be based on a test year ending December 31, 2007, with adjustments through June 2008.

Virginia E&R Costs Recovery Filing

As of March 31, 2008, APCo has $85 million of deferred Virginia incremental E&R costs. Currently APCo is recovering $26 million of the deferral for incremental costs incurred through September 30, 2006. APCo intends to file in May 2008 for recovery of deferred incremental E&R costs incurred from October 1, 2006 through December 31, 2007 which totals $46 million. The remaining deferral will be requested in a 2009 filing. As of March 31, 2008, APCo has $21 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 addition, if the Virginia SCC were to disallow any additional portion of APCo's deferral, it would also have an adverse affect on future results of operations and cash flows.

Virginia Fuel Clause Filing

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 back to June 1, 2007. The adjusted factor will increase 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 in the fourth quarter of 2008 to ensure accurate assignment of the prudently incurred PJM transmission line loss costs to APCo's Virginia jurisdictional operations. APCo 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 filed a notice of appeal to the Supreme Court of Virginia.

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 requests 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 March 31, 2008, APCo has deferred for future recovery pre-construction IGCC costs of $7 million applicable to Virginia. 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 on the basis of their 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. If necessary, APCo will seek recovery of its prudently incurred deferred pre-construction costs. If 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 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 itself, a $17 million increase in construction cost surcharges and $4 million of reliability expenditures, to become effective July 2008. 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 actuals and should have no earnings effect due to the deferral of any over/under-recovery of actual ENEC costs. However, if the WVPSC were to disallow the deferral of any costs including the incremental cost of PJM's recently revised costs associated with transmission line losses, it would have an adverse affect on future results of operations and cash flows. An order is expected by June 2008.

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, WV.

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. If APCo receives all necessary approvals, the plant could be completed as early as mid-2012. At the time of the filing, the cost of the plant was estimated at $2.2 billion. The Virginia SCC's decision to deny APCo's request to build an IGCC plant may have an impact on the project (See the "APCo's Virginia SCC Filing for an IGCC Plant" above). Through March 31, 2008, APCo deferred for future recovery pre-construction IGCC costs of $7 million applicable to the West Virginia jurisdiction and $2 million applicable to the FERC jurisdiction. If these 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

In January 2008, I&M filed for an increase in its Indiana base rates of $82 million including a return on equity of 11.5%. The base rate increase includes a previously approved $69 million annual reduction in depreciation expense. 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 $46 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 in early 2009.

Kentucky Rate Matters

Validity of Nonstatutory Surcharges

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

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could challenge KPCo's existing surcharges, which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, annual Rockport Plant capacity surcharge, merger surcredit and off-system sales credit rider. These surcharges are currently producing net annual revenues of approximately $10 million. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG stated 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 the 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 back to June 2007. If recovery of the incremental PJM costs through the fuel clause is denied, future results of operations and cash flows would be adversely affected. A decision is expected in May 2008.

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 August 2007, the OCC issued an order adopting the ALJ’s recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. In October 2007, the OCC 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. 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. PSO also filed prudence testimony in November 2007 covering the year 2006. The OCC staff and intervenors filed testimony in April 2008. Hearings are scheduled in May 2008. The only major issue raised in each of those proceedings was the alleged under allocation of off-system sales credits under the FERC-approved allocation agreements, which was determined not to be jurisdictional to the OCC. OCC orders applicable to both the 2005 and 2006 prudence proceedings are expected in 2008.

Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings and prudence reviews. 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.

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 denied PSO’s and OG&E’s applications for construction preapproval. The OCC stated that PSO failed to fully study other alternatives. 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. As a result of the OCC’s decision, PSO will restudy various alternative options 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. A hearing on the settlement is scheduled for 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. Should the OCC not approve the settlement agreement and if recovery of the remaining regulatory asset becomes no longer probable or is denied, future results of operations and cash flows would be adversely affected by the write off of the remaining regulatory asset.

Oklahoma 2007 Ice Storms

In October 2007, PSO filed with the OCC requesting recovery of $13 million of operation and maintenance expenses 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 such expense and to amortize this 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 a December 2007 ice storm.

In February 2008, PSO entered into a settlement agreement for recovery of costs from both ice storms. In March 2008, the OCC approved the settlement subject to an audit of the final December ice storm costs to be 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 will 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.

<u>Louisiana Rate Matters</u>

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. In April 2008, SWEPCo filed the first FRP anticipating that the LPSC would approve the settlement agreement. Based on the FRP, SWEPCo proposes to increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%.

If in years two or three 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. This separate credit rider will cease effective August 2011.

In addition, the settlement provides for a reduction in 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.

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 with 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. As of March 31, 2008, SWEPCo has capitalized pre-construction costs of $76 million and has contractual construction commitments of an additional $219 million. As of March 31, 2008, if the plant were to be cancelled, then cancellation fees of $59 million would terminate these construction commitments.

In March 2007, the PUCT approved SWEPCo's certificate for the facility. 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. 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. If SWEPCo 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.

Arkansas Rate Matters

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. As of March 31, 2008, including the joint owners' share, SWEPCo capitalized approximately $313 million of expenditures and has significant contractual construction commitments for an additional $838 million. As of March 31, 2008, if the plant were to be cancelled, then cancellation fees of $67 million would terminate these construction commitments.

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. SWEPCo is still awaiting approvals from the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers. Both approvals are expected to be received by the third quarter of 2008. The PUCT held hearings in October 2007. In January 2008, a Texas ALJ issued a report, which concluded that SWEPCo failed to prove there was a need for the plant. The Texas ALJ recommended that SWEPCo's application be denied. The PUCT has voted to reopen the record and conduct additional hearings. SWEPCo expects a decision from the PUCT in the last half of 2008. In March 2008, the LPSC approved the application to construct the Turk Plant. If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. If SWEPCo cannot recover its costs, it could 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

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 AEP and ultimately its internal load 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. 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.

Completed and in-process settlements cover $105 million of the $220 million of SECA revenues and will consume about $7 million of the reserve for refund, leaving approximately $115 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. AEP filed a Petition for Review of the FERC orders in this case in February 2008 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 to recover lost T&O revenues previously applied to reduce retail rates. 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 late 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, 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.

Potomac-Appalachian Transmission Highline (PATH) Rate Filing

In September 2007, AEP and Allegheny Energy Inc. (Allegheny) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC and its subsidiaries (PATH). The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM. Subsidiaries of both AEP and Allegheny provide services to the PATH companies through service agreements. PATH is not consolidated with AEP for financial reporting purposes.

In December 2007, PATH filed an application with the FERC for approval of a transmission formula rate to be collected during construction to recover its costs, including costs incurred prior to the formula rates going into effect. PATH requested an incentive return of 14.3% on its equity investment using a 50/50 debt to equity ratio, the recovery of deferred pre-operating, pre-construction costs and the recovery of construction financing costs through the inclusion of CWIP in rate base with a true-up to actual for these costs. The transmission formula rate will be collected from all PJM load serving entities. In addition to the rate recovery sought through the FERC, the PATH operating companies will seek certification and other regulatory approvals from the state commissions following completion of a routing study.

In February 2008, the FERC approved all of PATH's requests except for the cost of service formula and formula rate implementation protocols and ordered that the formula rates go into effect in March 2008. Settlement negotiations began and motions for rehearing were filed by intervening parties in March 2008. Management cannot predict the outcome of these proceedings.

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, debt service reserves and credit enhancements for issued bonds. As the Parent, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At March 31, 2008, the maximum future payments for all the LOCs are approximately $57 million with maturities ranging from April 2008 to March 2009.

Guarantees Of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of March 31, 2008, SWEPCo has collected approximately $35 million through a rider for final mine closure costs, of which approximately $17 million is recorded in Deferred Credits and Other and approximately $18 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all its costs. SWEPCo passes these costs 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 March 31, 2008, the maximum potential loss for these lease agreements was approximately $62 million ($40 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 has an initial term of five years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years; (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value; or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. We intend to renew the lease for the full twenty years. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment.

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 $46 million as of March 31, 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 $14 million ($9 million, net of tax) and SWEPCo's is approximately $16 million ($11 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. Cases are still pending that could affect CSPCo's share of jointly-owned units at Beckjord and Stuart stations. 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 and scheduled a settlement conference in May 2008. The Beckjord case is scheduled for a liability trial in May 2008. Beckjord is operated by Duke Energy Ohio, Inc.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, we might have for civil penalties under the pending CAA proceedings for our jointly-owned plants. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through 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 has been submitted to the Federal EPA and the DOJ for a 45-day comment period prior to entry.

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. TCEQ filed an amended Report during the fourth quarter of 2007, eliminating certain claims and reducing the recommended penalty amount to $122 thousand. 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. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration. In June 2007, TCEQ denied that motion. The permit alteration was appealed to the Travis County District Court, but would be resolved by entry of the consent decree in the federal citizen suit action. The District Court issued a stay while approval of the consent decree is pending.

On February 8, 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 early March 2008.

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

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The 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.

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 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 due May 2008. I&M cannot predict the cost of remediation or the amount of costs recoverable from third parties.

In those instances where we have been named a Potentially Responsible Party (PRP) or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites.

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 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 Texas state courts, Enron bankruptcy proceedings and in Federal courts in Texas and New York.

In 2002 and 2004, BOA filed lawsuits in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value.

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

In 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 dismissed our claims. In December 2007, the judge held that BOA is entitled to recover damages of approximately $347 million ($432 million and $427 million including interest at March 31, 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. In July 2006, the Court entered judgment 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. Several of these cases were dismissed on the basis of the filed rate doctrine. Plaintiffs in these cases appealed the decisions. In July 2007, the judge in the California cases stayed those proceedings pending a decision by the Ninth Circuit in the federal cases. In September 2007, the United States Court of Appeals for the Ninth Circuit reversed the dismissal of two of the cases and remanded those cases to the trial court. We will continue to defend each case where an AEP company is a defendant.

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 and argued before the U.S. Supreme Court in February 2008. 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 AND DISPOSITIONS

ACQUISITIONS

2008

None

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 contract.

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 March 31, 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 March 31, 2007 Condensed Consolidated Statement of Income.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the three months ended March 31, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 24	$ 10	$ 10
Interest Cost	63	59	28	26
Expected Return on Plan Assets	(84)	(85)	(28)	(26)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	9	15	3	3
Net Periodic Benefit Cost	$ 13	$ 13	$ 20	$ 20

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.

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 months ended March 31, 2008 and 2007 and balance sheet information as of March 31, 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 "FASB Staff Position FIN 39-1 Amendment of FASB No. 39" section of Note 2 for discussion of changes in netting certain balance sheet amounts.

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended March 31, 2008						
Revenues from:						
External Customers	$ 3,010(d)	$ 138	$ 271	$ 48	$ -	$ 3,467
Other Operating Segments	284(d)	4	(212)	(43)	(33)	-
Total Revenues	$ 3,294	$ 142	$ 59	$ 5	$ (33)	$ 3,467
Net Income	$ 410	$ 7	$ 1	$ 155	$ -	$ 573

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended March 31, 2007						
Revenues from:						
External Customers	$ 2,886(d)	$ 117	$ 115	$ 51	$ -	$ 3,169
Other Operating Segments	147(d)	3	(73)	(45)	(32)	-
Total Revenues	$ 3,033	$ 120	$ 42	$ 6	$ (32)	$ 3,169
Net Income (Loss)	$ 253	$ 15	$ (1)	$ 4	$ -	$ 271

March 31, 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	$ 46,055	$ 265	$ 575	$ 40	$ (245)	$ 46,690
Accumulated Depreciation and Amortization	16,144	63	119	8	(15)	16,319
Total Property, Plant and Equipment – Net	$ 29,911	$ 202	$ 456	$ 32	$ (230)	$ 30,371
Total Assets	$ 40,287	$ 340	$ 902	$ 12,707	$ (12,919)(b)	$ 41,317

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:
- 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.
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs, which netted to a $7 million after-tax loss for the first quarter of 2008.
- Revenue sharing related to the Plaquemine Cogeneration Facility.
- 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.

(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 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 $212 million. 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.

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 continue to evaluate the impact of the law change, but do not expect the law change to have a material impact on our results of operations, cash flows or financial condition.

On July 12, 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan's principal business tax. The new law was effective January 1, 2008 and replaced the Michigan Single Business Tax that expired at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

On September 30, 2007, the Governor of Michigan signed House Bill 5198, which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis differences triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15-year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. We have evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect our results of operations, cash flows or financial condition.

9. FINANCING ACTIVITIES

Long-term Debt

Type of Debt		March 31, 2008		December 31, 2007
		(in millions)		
Senior Unsecured Notes	$	10,349	$	9,905
Pollution Control Bonds		2,216		2,190
First Mortgage Bonds		-		19
Notes Payable		264		311
Securitization Bonds		2,183		2,257
Junior Subordinated Debentures		315		-
Notes Payable To Trust		113		113
Spent Nuclear Fuel Obligation (a)		261		259
Other Long-term Debt		3		2
Unamortized Discount (net)		(68)		(62)
Total Long-term Debt Outstanding		15,636		14,994
Less Portion Due Within One Year		716		792
Long-term Portion	$	14,920	$	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 $289 million and $285 million at March 31, 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 three 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	Senior Unsecured Notes		500	7.00	2038
Non-Registrant:					
TCC	Pollution Control Bonds		120	5.125	2030
Total Issuances		$	935(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 $916 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:				
CSPCo	Senior Unsecured Notes	$ 52	6.51	2008
I&M	Pollution Control Bonds	45	Variable	2009
I&M	Pollution Control Bonds	50	Variable	2025
OPCo	Notes Payable	1	6.81	2008
OPCo	Notes Payable	6	6.27	2009
SWEPCo	Notes Payable	1	4.47	2011
SWEPCo	Notes Payable	1	Variable	2008
Non-Registrant:				
AEP Subsidiaries	Notes Payable	2	Variable	2017
AEGCo	Senior Unsecured Notes	4	6.33	2037
AEPSC	Mortgage Notes	34	9.60	2008
TCC	Securitization Bonds	29	5.01	2008
TCC	Securitization Bonds	45	4.98	2010
TCC	First Mortgage Bonds	19	7.125	2008
Total Retirements and Principal Payments		$ 289		

In April 2008, I&M issued $40 million of 5.25% Pollution Control Bonds due in 2025. TNC issued $30 million of 5.89% and $70 million of 6.76% Senior Unsecured Notes due in 2018 and 2038, respectively.

In April 2008, CSPCo remarketed its outstanding $44.5 million and $56 million Pollution Control Bonds, resulting in new interest rates of 4.85% and 5.10%, respectively. SWEPCo remarketed its outstanding $81.7 million Pollution Control Bonds, resulting in a new interest rate of 4.95%. TCC remarketed its outstanding $40.9 million Pollution Control Bonds, resulting in a new interest rate of 5.625%. No proceeds were received related to these remarketings. The principal amounts of the Pollution Control Bonds are reflected in Long-term Debt on our Condensed Consolidated Balance Sheets as of March 31, 2008.

In April 2008, APCo repurchased its $40 million and $30 million of variable rate interest Pollution Control Bonds, each due in 2019, and $17.5 million of variable rate interest Pollution Control Bonds due in 2021. CSPCo repurchased its $48.6 million of variable rate interest Pollution Control Bonds due in 2038.

In April 2008, TCC retired $60 million and $60.3 million of variable interest rate Pollution Control Bonds, each due in 2028.

As of March 31, 2008, we had $1.4 billion outstanding of tax-exempt long-term debt (Pollution Control Bonds) sold at auction rates that reset every 7, 28 or 35 days. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation, Financial Guaranty Insurance Co., MBIA Insurance Corporation and XL Capital Assurance Inc. 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. During the first quarter of 2008, we reduced our outstanding auction rate securities by redeeming or repurchasing $95 million of such debt securities. In April 2008, we converted, refunded or provided notice to convert or refund $940 million of our outstanding auction rate securities. We plan to continue this conversion and refunding process for the remaining $471 million to other permitted modes, including term-put and fixed-rate structures through the third quarter of 2008. The conversions will likely result in higher interest charges compared to prior year but lower than the failed auction rates for this tax-exempt long-term debt.

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:

	March 31, 2008		December 31, 2007	
Type of Debt	**Outstanding Amount (in thousands)**	**Interest Rate (a)**	**Outstanding Amount (in thousands)**	**Interest Rate (a)**
Commercial Paper – AEP	$ 408,959	3.66 %	$ 659,135	5.54 %
Commercial Paper – JMG (b)	-	-	701	5.35 %
Line of Credit – Sabine Mining Company (c)	-	-	285	5.25 %
Total	$ 408,959		$ 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 March 31, 2008, we had credit facilities totaling $3 billion to support our commercial paper program. The facilities are structured as two $1.5 billion credit facilities of which $300 million may be issued under each credit facility as letters of credit. 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.

APPALACHIAN POWER COMPANY

AND SUBSIDIARIES

Results of Operations

First Quarter of 2008 Compared to First Quarter of 2007

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

First Quarter of 2007		$	70
Changes in Gross Margin:			
Retail Margins	(20)		
Off-system Sales	16		
Transmission Revenues	1		
Total Change in Gross Margin			(3)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(20)		
Depreciation and Amortization	(3)		
Taxes Other Than Income Taxes	(3)		
Carrying Costs Income	6		
Other Income	1		
Interest Expense	(12)		
Total Change in Operating Expenses and Other			(31)
Income Tax Expense			19
First Quarter of 2008		$	55

Net Income decreased $15 million to $55 million in 2008 primarily due to an increase in Operating Expenses and Other of $31 million, partially offset by a decrease in Income Tax Expense of $19 million.

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

- Retail Margins decreased $20 million primarily due to higher capacity settlement expenses under the Interconnection Agreement and an increase in refunds to customers of off-system sales margins. These decreases were partially offset by an increase in the recovery of APCo's environmental and reliability costs and an increase in retail sales related to customer usage.
- Margins from Off-system Sales increased $16 million primarily due to higher physical sales margins partially offset by lower trading margins.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $20 million primarily due to a $9 million increase in steam generation expenses primarily for maintenance at the Mountaineer Plant and an increase of $5 million in distribution maintenance expenses resulting from Virginia and West Virginia wind storm damage. In addition, operational expenses increased by $8 million due to decreased Transmission Equalization Agreement credits resulting from APCo's peak demand set in February 2007 and increased employee-related expenses.
- Depreciation and Amortization expenses increased $3 million primarily due to the amortization of carrying charges and depreciation expense that are being collected through the Virginia E&R surcharges.
- Taxes Other Than Income Taxes increased $3 million primarily due to higher franchise taxes which resulted from an amended tax return recognized in 2007.
- Carrying Costs Income increased $6 million related to carrying costs associated with the Virginia E&R case.
- Interest Expense increased $12 million primarily due to an $8 million increase in interest expense from long-term debt issuances and a $3 million decrease in the debt component of AFUDC resulting from the reapplication of SFAS 71.
- Income Tax Expense decreased $19 million primarily due to a decrease in pretax book income and state income taxes.

Financial Condition

Credit Ratings

S&P and Fitch currently have APCo on stable outlook, while 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+

Cash Flow

Cash flows for the three months ended March 31, 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	118,832	176,029
Investing Activities	(409,179)	(200,894)
Financing Activities	290,804	24,534
Net Increase (Decrease) in Cash and Cash Equivalents	457	(331)
Cash and Cash Equivalents at End of Period	$ 2,652	$ 1,987

Operating Activities

Net Cash Flows From Operating Activities were $119 million in 2008. APCo produced income of $55 million during the period and a noncash expense item of $63 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items in 2008. The $32 million cash inflow from Accounts Receivable, Net was primarily due to a settlement of allowance sales to affiliated companies. The $20 million cash inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory to reflect planned outages. The $27 million change in Fuel Over/Under Recovery, Net resulted in a net under recovery of fuel cost in both Virginia and West Virginia.

Net Cash Flows From Operating Activities were $176 million in 2007. APCo produced income of $70 million during the period and a noncash expense item of $59 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 had no significant items in 2007.

Investing Activities

Net Cash Flows Used For Investing Activities during 2008 and 2007 were $409 million and $201 million, respectively. Construction Expenditures were $159 million and $202 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 include the installation of selective catalytic reduction equipment on APCo's plants and the flue gas desulfurization project at the Amos and Mountaineer Plants. In February 2007, environmental upgrades were completed for the Mountaineer Plant. In addition, APCo's investments in the Utility Money Pool increased by $262 million in 2008. For the remainder of 2008, APCo expects construction expenditures to be approximately $620 million.

Financing Activities

Net Cash Flows From Financing Activities were $291 million in 2008. APCo received Capital Contributions from AEP of $75 million. APCo issued $500 million in senior unsecured notes in March 2008. APCo had a net decrease of $275 million in borrowings from the Utility Money Pool.

Net Cash Flows From Financing Activities were $25 million in 2007. APCo had a net increase of $48 million in borrowings from the Utility Money Pool and paid $15 million in dividends on common stock.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2008 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Debt	$ 500,000	7.000	2038

Retirements

None

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 discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 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 March 31, 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 March 31, 2008
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 139,911	$ 5,003	$ -	$ (3,346)	$ 141,568
Noncurrent Assets	77,550	852	-	(4,827)	73,575
Total MTM Derivative Contract Assets	217,461	5,855	-	(8,173)	215,143
Current Liabilities	(129,250)	(23,448)	(3,734)	11,797	(144,635)
Noncurrent Liabilities	(48,108)	(54)	(4,306)	554	(51,914)
Total MTM Derivative Contract Liabilities	(177,358)	(23,502)	(8,040)	12,351	(196,549)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 40,103	$ (17,647)	$ (8,040)	$ 4,178	$ 18,594

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 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		(8,194)
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)		864
Changes in Fair Value Due to Market Fluctuations During the Period (c)		(204)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		1,767
Total MTM Risk Management Contract Net Assets		40,103
Net Cash Flow & Fair Value Hedge Contracts		(17,647)
DETM Assignment (e)		(8,040)
Collateral Deposits		4,178
Ending Net Risk Management Assets at March 31, 2008	$	18,594

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/ liabilities 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 March 31, 2008
(in thousands)

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ (3,547)	$ (893)	$ (20)	$ -	$ -	$ -	$ (4,460)
Level 2 (b)	6,543	12,561	9,182	637	470	-	29,393
Level 3 (c)	25	1,152	(2,090)	(19)	(11)	-	(943)
Total	$ 3,021	$ 12,820	$ 7,072	$ 618	$ 459	$ -	$ 23,990
Dedesignated Risk Management Contracts (d)	3,577	4,602	4,565	1,778	1,591	-	16,113
Total MTM Risk Management Contract Net Assets	$ 6,598	$ 17,422	$ 11,637	$ 2,396	$ 2,050	$ -	$ 40,103

(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 forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. 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 March 31, 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
Three Months Ended March 31, 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	(11,413)	(3,105)	206	(14,312)
Reclassifications from AOCI for Cash Flow Hedges Settled	110	387	2	499
Ending Balance in AOCI March 31, 2008	$ (10,520)	$ (9,320)	$ 83	$ (19,757)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $12.7 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 March 31, 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:

Three Months Ended March 31, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$566	$709	$356	$161	$455	$2,328	$569	$117

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

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which APCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. The estimated EaR on APCo's debt portfolio was $4.6 million.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
REVENUES		
Electric Generation, Transmission and Distribution	$ 641,457	$ 601,546
Sales to AEP Affiliates	90,090	61,545
Other	3,480	2,637
TOTAL	735,027	665,728
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	173,830	171,186
Purchased Electricity for Resale	43,199	35,950
Purchased Electricity from AEP Affiliates	189,595	127,601
Other Operation	75,531	67,629
Maintenance	57,844	45,753
Depreciation and Amortization	62,572	59,160
Taxes Other Than Income Taxes	23,991	21,275
TOTAL	626,562	528,554
OPERATING INCOME	108,465	137,174
Other Income (Expense):		
Interest Income	2,769	639
Carrying Costs Income	9,586	3,166
Allowance for Equity Funds Used During Construction	1,496	2,777
Interest Expense	(44,140)	(31,823)
INCOME BEFORE INCOME TAX EXPENSE	78,176	111,933
Income Tax Expense	22,863	41,706
NET INCOME	55,313	70,227
Preferred Stock Dividend Requirements including Capital Stock Expense	238	238
EARNINGS APPLICABLE TO COMMON STOCK	$ 55,075	$ 69,989

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

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 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			(15,000)		(15,000)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		38	(38)		-
TOTAL					2,018,289
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,030				(7,484)	(7,484)
NET INCOME			70,227		70,227
TOTAL COMPREHENSIVE INCOME					62,743
MARCH 31, 2007	$ 260,458	$ 1,025,032	$ 857,817	$ (62,275)	$ 2,081,032
DECEMBER 31, 2007	$ 260,458	$ 1,025,149	$ 831,612	$ (35,187)	$ 2,082,032
EITF 06-10 Adoption, Net of Tax of $1,175			(2,181)		(2,181)
SFAS 157 Adoption, Net of Tax of $154			(286)		(286)
Capital Contribution from Parent		75,000			75,000
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		39	(38)		1
TOTAL					2,154,366
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,438				(13,813)	(13,813)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $449				833	833
NET INCOME			55,313		55,313
TOTAL COMPREHENSIVE INCOME					42,333
MARCH 31, 2008	$ 260,458	$ 1,100,188	$ 884,220	$ (48,167)	$ 2,196,699

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

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,652	$ 2,195
Advances to Affiliates	261,823	-
Accounts Receivable:		
Customers	165,994	176,834
Affiliated Companies	85,530	113,582
Accrued Unbilled Revenues	30,578	38,397
Miscellaneous	1,736	2,823
Allowance for Uncollectible Accounts	(5,861)	(13,948)
Total Accounts Receivable	277,977	317,688
Fuel	61,287	82,203
Materials and Supplies	77,159	76,685
Risk Management Assets	141,568	62,955
Prepayments and Other	24,396	16,369
TOTAL	846,862	558,095
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,623,812	3,625,788
Transmission	1,677,426	1,675,081
Distribution	2,400,382	2,372,687
Other	356,552	351,827
Construction Work in Progress	779,850	713,063
Total	8,838,022	8,738,446
Accumulated Depreciation and Amortization	2,610,635	2,591,833
TOTAL - NET	6,227,387	6,146,613
OTHER NONCURRENT ASSETS		
Regulatory Assets	666,207	652,739
Long-term Risk Management Assets	73,575	72,366
Deferred Charges and Other	205,816	191,871
TOTAL	945,598	916,976
TOTAL ASSETS	$ 8,019,847	$ 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
March 31, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 275,257
Accounts Payable:		
General	226,940	241,871
Affiliated Companies	102,784	106,852
Long-term Debt Due Within One Year – Nonaffiliated	287,229	239,732
Risk Management Liabilities	144,635	51,708
Customer Deposits	48,828	45,920
Accrued Taxes	53,966	58,519
Accrued Interest	53,051	41,699
Other	88,254	139,476
TOTAL	1,005,687	1,201,034
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,952,929	2,507,567
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	51,914	47,357
Deferred Income Taxes	973,047	948,891
Regulatory Liabilities and Deferred Investment Tax Credits	505,872	505,556
Deferred Credits and Other	215,947	211,495
TOTAL	4,799,709	4,320,866
TOTAL LIABILITIES	5,805,396	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	1,100,188	1,025,149
Retained Earnings	884,220	831,612
Accumulated Other Comprehensive Income (Loss)	(48,167)	(35,187)
TOTAL	2,196,699	2,082,032
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 8,019,847	$ 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 Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 55,313	$ 70,227
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	62,572	59,160
Deferred Income Taxes	25,066	(3,901)
Carrying Costs Income	(9,586)	(3,166)
Allowance for Equity Funds Used During Construction	(1,496)	(2,777)
Mark-to-Market of Risk Management Contracts	(1,658)	(3,255)
Change in Other Noncurrent Assets	(13,102)	(9,970)
Change in Other Noncurrent Liabilities	(5,555)	30,172
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	32,344	8,849
Fuel, Materials and Supplies	20,442	(1,034)
Accounts Payable	4,235	(19,891)
Accrued Taxes, Net	(2,942)	29,539
Accrued Interest	11,351	21,608
Fuel Over/Under Recovery, Net	(26,584)	12,987
Other Current Assets	(6,690)	2,074
Other Current Liabilities	(24,878)	(14,593)
Net Cash Flows from Operating Activities	118,832	176,029
INVESTING ACTIVITIES		
Construction Expenditures	(158,722)	(202,007)
Change in Other Cash Deposits, Net	-	(29)
Change in Advances to Affiliates, Net	(261,823)	-
Proceeds from Sales of Assets	11,366	1,142
Net Cash Flows Used for Investing Activities	(409,179)	(200,894)
FINANCING ACTIVITIES		
Capital Contribution from Parent	75,000	-
Issuance of Long-term Debt – Nonaffiliated	492,325	-
Change in Advances from Affiliates, Net	(275,257)	47,885
Retirement of Long-term Debt – Nonaffiliated	(3)	(3)
Principal Payments for Capital Lease Obligations	(1,061)	(1,112)
Amortization of Funds From Amended Coal Contract	-	(7,036)
Dividends Paid on Common Stock	-	(15,000)
Dividends Paid on Cumulative Preferred Stock	(200)	(200)
Net Cash Flows from Financing Activities	290,804	24,534
Net Increase (Decrease) in Cash and Cash Equivalents	457	(331)
Cash and Cash Equivalents at Beginning of Period	2,195	2,318
Cash and Cash Equivalents at End of Period	$ 2,652	$ 1,987
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 35,527	$ 7,084
Net Cash Paid for Income Taxes	338	7,775
Noncash Acquisitions Under Capital Leases	478	444
Construction Expenditures Included in Accounts Payable at March 31,	83,766	113,021

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.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments, Guarantees and Contingencies	Note 4
Benefit Plans	Note 6
Business Segments	Note 7
Income Taxes	Note 8
Financing Activities	Note 9

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

First Quarter of 2008 Compared to First Quarter of 2007

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

First Quarter of 2007		$ 47
Changes in Gross Margin:		
Retail Margins	52	
Off-system Sales	10	
Transmission Revenues	1	
Total Change in Gross Margin		63
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(13)	
Depreciation and Amortization	2	
Taxes Other Than Income Taxes	(4)	
Interest Expense	(4)	
Other	3	
Total Change in Operating Expenses and Other		(16)
Income Tax Expense		(18)
First Quarter of 2008		$ 76

Net Income increased $29 million to $76 million in 2008. The key driver of the increase was a $63 million increase in Gross Margin offset by an $18 million increase in Income Tax Expense and a $16 million increase in Operating Expenses and Other.

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

- Retail Margins increased $52 million primarily due to:
  - A $32 million increase in rate revenues related to CSPCo's RSP (see "Ohio Rate Matters" section of Note 3).
  - A $32 million decrease in capacity settlement charges due to recent plant acquisitions and changes in relative peak demands of AEP Power Pool members under the Interconnection Agreement.
  - An $11 million increase in industrial revenue due to increased usage by Ormet, a major industrial customer.

  These increases were partially offset by:
  - A $14 million decrease in fuel margins.
- Margins from Off-system Sales increased $10 million primarily due to higher physical sales margins and higher trading margins.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $13 million primarily due to:
  - An $8 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 boiler plant maintenance expenses primarily related to work performed at the Conesville and Stuart Plants.
- 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 $4 million due to increases in property taxes, state excise taxes and gross receipt taxes.
- Interest Expense increased $4 million primarily due to increases in long-term borrowings and short-term borrowings from the Utility Money Pool and a reduction in the debt component of AFUDC.
- Income Tax Expense increased $18 million primarily due to an increase in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 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 $4.7 million.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
REVENUES		
Electric Generation, Transmission and Distribution	$ 505,324	$ 423,466
Sales to AEP Affiliates	35,108	23,013
Other	1,217	1,433
TOTAL	541,649	447,912
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	85,127	75,862
Purchased Electricity for Resale	42,186	31,311
Purchased Electricity from AEP Affiliates	94,104	83,541
Other Operation	73,066	61,159
Maintenance	23,231	22,564
Depreciation and Amortization	48,602	50,297
Taxes Other Than Income Taxes	44,556	40,582
TOTAL	410,872	365,316
OPERATING INCOME	130,777	82,596
Other Income (Expense):		
Interest Income	2,339	422
Carrying Costs Income	1,766	1,092
Allowance for Equity Funds Used During Construction	855	772
Interest Expense	(19,239)	(15,281)
INCOME BEFORE INCOME TAX EXPENSE	116,498	69,601
Income Tax Expense	40,345	22,620
NET INCOME	76,153	46,981
Capital Stock Expense	39	39
EARNINGS APPLICABLE TO COMMON STOCK	$ 76,114	$ 46,942

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

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 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			(20,000)		(20,000)
Capital Stock Expense		39	(39)		-
TOTAL					1,032,995
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,841				(5,276)	(5,276)
NET INCOME			46,981		46,981
TOTAL COMPREHENSIVE INCOME					41,705
MARCH 31, 2007	$ 41,026	$ 580,231	$ 480,707	$ (27,264)	$ 1,074,700
DECEMBER 31, 2007	$ 41,026	$ 580,349	$ 561,696	$ (18,794)	$ 1,164,277
EITF 06-10 Adoption, Net of Tax of $589			(1,095)		(1,095)
SFAS 157 Adoption, Net of Tax of $170			(316)		(316)
Common Stock Dividends			(37,500)		(37,500)
Capital Stock Expense		39	(39)		-
TOTAL					1,125,366
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,553				(6,598)	(6,598)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $152				283	283
NET INCOME			76,153		76,153
TOTAL COMPREHENSIVE INCOME					69,838
MARCH 31, 2008	$ 41,026	$ 580,388	$ 598,899	$ (25,109)	$ 1,195,204

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

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,616	$ 1,389
Other Cash Deposits	53,760	53,760
Accounts Receivable:		
Customers	68,611	57,268
Affiliated Companies	19,614	32,852
Accrued Unbilled Revenues	20,685	14,815
Miscellaneous	9,354	9,905
Allowance for Uncollectible Accounts	(2,604)	(2,563)
Total Accounts Receivable	115,660	112,277
Fuel	29,677	35,849
Materials and Supplies	36,313	36,626
Emission Allowances	14,594	16,811
Risk Management Assets	78,080	33,558
Prepayments and Other	14,369	9,960
TOTAL	344,069	300,230
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,073,747	2,072,564
Transmission	553,853	510,107
Distribution	1,565,111	1,552,999
Other	202,962	198,476
Construction Work in Progress	436,001	415,327
Total	4,831,674	4,749,473
Accumulated Depreciation and Amortization	1,721,170	1,697,793
TOTAL - NET	3,110,504	3,051,680
OTHER NONCURRENT ASSETS		
Regulatory Assets	227,062	235,883
Long-term Risk Management Assets	43,808	41,852
Deferred Charges and Other	163,218	181,563
TOTAL	434,088	459,298
TOTAL ASSETS	$ 3,888,661	$ 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
March 31, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 163,999	$ 95,199
Accounts Payable:		
General	119,321	113,290
Affiliated Companies	58,734	65,292
Long-term Debt Due Within One Year – Nonaffiliated	108,550	112,000
Risk Management Liabilities	81,151	28,237
Customer Deposits	43,029	43,095
Accrued Taxes	177,810	179,831
Other	65,117	96,892
TOTAL	817,711	733,836
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,037,769	1,086,224
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	30,982	27,419
Deferred Income Taxes	446,119	437,306
Regulatory Liabilities and Deferred Investment Tax Credits	162,382	165,635
Deferred Credits and Other	98,494	96,511
TOTAL	1,875,746	1,913,095
TOTAL LIABILITIES	2,693,457	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	580,388	580,349
Retained Earnings	598,899	561,696
Accumulated Other Comprehensive Income (Loss)	(25,109)	(18,794)
TOTAL	1,195,204	1,164,277
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,888,661	$ 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 Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 76,153	$ 46,981
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	48,602	50,297
Deferred Income Taxes	872	(716)
Allowance for Equity Funds Used During Construction	(855)	(772)
Mark-to-Market of Risk Management Contracts	(1,499)	1,936
Deferred Property Taxes	21,728	18,954
Change in Other Noncurrent Assets	(11,440)	(1,232)
Change in Other Noncurrent Liabilities	1,292	(15,510)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(3,383)	19,839
Fuel, Materials and Supplies	6,485	3,218
Accounts Payable	(6,756)	(7,659)
Accrued Taxes, Net	(2,001)	(8,651)
Other Current Assets	(2,211)	4,531
Other Current Liabilities	(20,972)	(4,515)
Net Cash Flows from Operating Activities	106,015	106,701
INVESTING ACTIVITIES		
Construction Expenditures	(84,513)	(85,641)
Change in Advances to Affiliates, Net	-	(922)
Other	150	169
Net Cash Flows Used for Investing Activities	(84,363)	(86,394)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	68,800	(696)
Retirement of Long-term Debt – Nonaffiliated	(52,000)	-
Principal Payments for Capital Lease Obligations	(725)	(693)
Dividends Paid on Common Stock	(37,500)	(20,000)
Net Cash Flows Used for Financing Activities	(21,425)	(21,389)
Net Increase (Decrease) in Cash and Cash Equivalents	227	(1,082)
Cash and Cash Equivalents at Beginning of Period	1,389	1,319
Cash and Cash Equivalents at End of Period	$ 1,616	$ 237
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 24,351	$ 20,132
Net Cash Paid (Received) for Income Taxes	2,494	(2,907)
Noncash Acquisitions Under Capital Leases	355	275
Construction Expenditures Included in Accounts Payable at March 31,	48,392	20,636

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.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments, Guarantees and Contingencies	Note 4
Acquisition	Note 5
Benefit Plans	Note 6
Business Segments	Note 7
Income Taxes	Note 8
Financing Activities	Note 9

INDIANA MICHIGAN POWER COMPANY

AND SUBSIDIARIES

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

Results of Operations

First Quarter of 2008 Compared to First Quarter of 2007

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

First Quarter of 2007		$ 29
Changes in Gross Margin:		
Retail Margins	1	
FERC Municipals and Cooperatives	4	
Off-system Sales	9	
Transmission Revenues	(1)	
Other	7	
Total Change in Gross Margin		20
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(8)	
Depreciation and Amortization	25	
Taxes Other Than Income Taxes	(2)	
Other Income	1	
Total Change in Operating Expenses and Other		16
Income Tax Expense		(10)
First Quarter of 2008		$ 55

Net Income increased $26 million to $55 million in 2008. The key drivers of the increase were a $20 million increase in Gross Margin and a $16 million decrease in Operating Expenses and Other partially offset by a $10 million increase in Income Tax Expense.

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

- FERC Municipals and Cooperatives margins increased $4 million due to higher prices in 2008.
- Margins from Off-system Sales increased $9 million primarily due to higher physical sales margins partially offset by lower trading margins.
- Other revenues increased $7 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 a return approved under a regulatory order impacting I&M's earnings.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $8 million primarily due to higher operation and maintenance expenses for RTD caused by increased barging activity.
- Depreciation and Amortization expense decreased $25 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 $10 million primarily due to an increase in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 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 Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
REVENUES		
Electric Generation, Transmission and Distribution	$ 431,592	$ 405,164
Sales to AEP Affiliates	76,512	67,429
Other – Affiliated	23,219	12,667
Other – Nonaffiliated	5,826	7,609
TOTAL	537,149	492,869
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	101,241	96,117
Purchased Electricity for Resale	21,483	17,940
Purchased Electricity from AEP Affiliates	92,641	77,513
Other Operation	120,366	120,733
Maintenance	51,221	42,430
Depreciation and Amortization	31,722	56,307
Taxes Other Than Income Taxes	19,902	17,994
TOTAL	438,576	429,034
OPERATING INCOME	98,573	63,835
Other Income (Expense):		
Interest Income	829	588
Allowance for Equity Funds Used During Construction	880	265
Interest Expense	(19,202)	(19,821)
INCOME BEFORE INCOME TAX EXPENSE	81,080	44,867
Income Tax Expense	25,822	15,404
NET INCOME	55,258	29,463
Preferred Stock Dividend Requirements	85	85
EARNINGS APPLICABLE TO COMMON STOCK	$ 55,173	$ 29,378

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

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 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			(10,000)		(10,000)
Preferred Stock Dividends			(85)		(85)
TOTAL					1,279,681
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,850				(5,293)	(5,293)
NET INCOME			29,463		29,463
TOTAL COMPREHENSIVE INCOME					24,170
MARCH 31, 2007	$ 56,584	$ 861,290	$ 406,321	$ (20,344)	$ 1,303,851
DECEMBER 31, 2007	$ 56,584	$ 861,291	$ 483,499	$ (15,675)	$ 1,385,699
EITF 06-10 Adoption, Net of Tax of $753			(1,398)		(1,398)
Common Stock Dividends			(18,750)		(18,750)
Preferred Stock Dividends			(85)		(85)
TOTAL					1,365,466
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,208				(5,958)	(5,958)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $59				110	110
NET INCOME			55,258		55,258
TOTAL COMPREHENSIVE INCOME					49,410
MARCH 31, 2008	$ 56,584	$ 861,291	$ 518,524	$ (21,523)	$ 1,414,876

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

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,731	$ 1,139
Accounts Receivable:		
Customers	69,932	70,995
Affiliated Companies	61,930	92,018
Accrued Unbilled Revenues	19,501	16,207
Miscellaneous	1,783	1,335
Allowance for Uncollectible Accounts	(2,769)	(2,711)
Total Accounts Receivable	150,377	177,844
Fuel	50,379	61,342
Materials and Supplies	142,240	141,384
Risk Management Assets	73,579	32,365
Accrued Tax Benefits	786	4,438
Prepayments and Other	20,718	11,091
TOTAL	439,810	429,603
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,488,509	3,529,524
Transmission	1,088,696	1,078,575
Distribution	1,211,073	1,196,397
Other (including nuclear fuel and coal mining)	624,600	626,390
Construction Work in Progress	134,279	122,296
Total	6,547,157	6,553,182
Accumulated Depreciation, Depletion and Amortization	2,969,464	2,998,416
TOTAL - NET	3,577,693	3,554,766
OTHER NONCURRENT ASSETS		
Regulatory Assets	252,438	246,435
Spent Nuclear Fuel and Decommissioning Trusts	1,324,398	1,346,798
Long-term Risk Management Assets	41,740	40,227
Deferred Charges and Other	138,219	128,623
TOTAL	1,756,795	1,762,083
TOTAL ASSETS	$ 5,774,298	$ 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
March 31, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 185,938	$ 45,064
Accounts Payable:		
General	91,756	184,435
Affiliated Companies	58,556	61,749
Long-term Debt Due Within One Year – Nonaffiliated	50,000	145,000
Risk Management Liabilities	76,295	27,271
Customer Deposits	27,146	26,445
Accrued Taxes	97,369	60,995
Obligations Under Capital Leases	43,749	43,382
Other	107,027	130,232
TOTAL	737,836	724,573
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,424,713	1,422,427
Long-term Risk Management Liabilities	29,587	26,348
Deferred Income Taxes	336,058	321,716
Regulatory Liabilities and Deferred Investment Tax Credits	755,477	789,346
Asset Retirement Obligations	863,680	852,646
Deferred Credits and Other	203,991	215,617
TOTAL	3,613,506	3,628,100
TOTAL LIABILITIES	4,351,342	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	518,524	483,499
Accumulated Other Comprehensive Income (Loss)	(21,523)	(15,675)
TOTAL	1,414,876	1,385,699
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,774,298	$ 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 Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 55,258	$ 29,463
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	31,722	56,307
Deferred Income Taxes	5,191	(3,638)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(881)	12,191
Allowance for Equity Funds Used During Construction	(880)	(265)
Mark-to-Market of Risk Management Contracts	(1,308)	2,316
Amortization of Nuclear Fuel	21,619	16,372
Deferred Property Taxes	(11,412)	(10,836)
Change in Other Noncurrent Assets	658	5,994
Change in Other Noncurrent Liabilities	14,234	(1,971)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	27,467	38,789
Fuel, Materials and Supplies	10,107	14,985
Accounts Payable	408	(38,233)
Accrued Taxes, Net	40,026	39,525
Accrued Rent – Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(6,718)	737
Other Current Liabilities	(39,998)	(35,427)
Net Cash Flows from Operating Activities	163,957	144,773
INVESTING ACTIVITIES		
Construction Expenditures	(67,945)	(62,252)
Purchases of Investment Securities	(132,311)	(204,874)
Sales of Investment Securities	113,951	183,927
Acquisitions of Nuclear Fuel	(98,385)	(5,366)
Proceeds from Sales of Assets and Other	2,815	248
Net Cash Flows Used for Investing Activities	(181,875)	(88,317)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	140,874	(45,414)
Retirement of Long-term Debt – Nonaffiliated	(95,000)	-
Principal Payments for Capital Lease Obligations	(8,529)	(1,573)
Dividends Paid on Common Stock	(18,750)	(10,000)
Dividends Paid on Cumulative Preferred Stock	(85)	(85)
Net Cash Flows from (Used for) Financing Activities	18,510	(57,072)
Net Increase (Decrease) in Cash and Cash Equivalents	592	(616)
Cash and Cash Equivalents at Beginning of Period	1,139	1,369
Cash and Cash Equivalents at End of Period	$ 1,731	$ 753
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 20,216	$ 15,048
Net Cash Received for Income Taxes	(1,118)	(2,768)
Noncash Acquisitions Under Capital Leases	2,023	369
Construction Expenditures Included in Accounts Payable at March 31,	16,280	20,243

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.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments, Guarantees and Contingencies	Note 4
Benefit Plans	Note 6
Business Segments	Note 7
Income Taxes	Note 8
Financing Activities	Note 9

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2008 Compared to First Quarter of 2007

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

First Quarter of 2007		$ 79
Changes in Gross Margin:		
Retail Margins	41	
Off-system Sales	13	
Other	7	
Total Change in Gross Margin		61
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	24	
Depreciation and Amortization	16	
Taxes Other Than Income Taxes	(3)	
Other Income	2	
Interest Expense	(8)	
Total Change in Operating Expenses and Other		31
Income Tax Expense		(33)
First Quarter of 2008		$ 138

Net Income increased $59 million to $138 million in 2008. The key drivers of the increase were a $61 million increase in Gross Margin and a $31 million decrease in Operating Expenses and Other offset by a $33 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 $41 million primarily due to the following:
  - A $58 million increase related to a coal contract amendment which reduced future deliveries to OPCo in exchange for consideration received.
  - An $11 million increase related to new rates implemented as approved by the PUCO in OPCo's RSP.
  - A $6 million increase primarily related to increased usage by Ormet, an industrial customer. See "Ormet" section of Note 3.

  These increases were partially offset by:
  - A $40 million decrease related to increased fuel, consumable and allowance costs.
- Margins from Off-system Sales increased $13 million due to higher physical sales margins and higher trading margins.
- Other revenues increased $7 million primarily due to increased gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $24 million primarily due to the higher maintenance and removal costs for planned and forced outages at the Gavin and Mitchell Plants in 2007.
- Depreciation and Amortization decreased $16 million primarily due to:
  - An $18 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 $7 million increase in depreciation related to environmental improvements placed in service at the Mitchell Plant during 2007.
- Taxes Other Than Income Taxes increased $3 million primarily due to increased taxable property value.
- Interest Expense increased $8 million primarily due to the issuance of additional long-term debt and a decrease in the debt component of AFUDC as a result of Mitchell Plant environmental improvements placed in service. These decreases were partially offset by a decrease in interest expense related to OPCo's borrowings from the Utility Money Pool as a result of reduced borrowings.
- Income Tax Expense increased $33 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+

Cash Flow

Cash flows for the three months ended March 31, 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	151,617	96,864
Investing Activities	(140,253)	(306,826)
Financing Activities	(14,413)	209,598
Net Decrease in Cash and Cash Equivalents	(3,049)	(364)
Cash and Cash Equivalents at End of Period	$ 3,617	$ 1,261

Operating Activities

Net Cash Flows From Operating Activities were $152 million in 2008. OPCo produced Net Income of $138 million during the period and a noncash expense item of $69 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to Accounts Receivable, Net. Accounts Receivable, Net had a $22 million outflow primarily due to a coal contract amendment which reduced future deliveries in exchange for consideration received.

Net Cash Flows From Operating Activities were $97 million in 2007. OPCo produced income of $79 million during the period and a noncash expense item of $84 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital primarily relates to a number of items. Accounts Receivable, Net had a $38 million outflow due to temporary timing differences of rent receivables and an increase in billed revenue for electric customers. Fuel, Materials and Supplies had a $20 million outflow due to an increase in coal inventories. Accounts Payable had a $26 million outflow primarily due to emission allowance payments in January 2007.

Investing Activities

Net Cash Used For Investing Activities were $140 million and $307 million in 2008 and 2007, respectively. Construction Expenditures were $142 million and $302 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 $530 million.

Financing Activities

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

Net Cash Flows From Financing Activities were $210 million in 2007 primarily due to a net increase of $216 million in borrowings from the Utility Money Pool.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2008 were:

<u>Issuances</u>

None

<u>Retirements</u>

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

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.

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 March 31, 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 March 31, 2008
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 113,255	$ 1,939	$ -	$ (2,420)	$ 112,774
Noncurrent Assets	58,242	596	-	(3,378)	55,460
Total MTM Derivative Contract Assets	171,497	2,535	-	(5,798)	168,234
Current Liabilities	(107,058)	(18,774)	(2,613)	10,016	(118,429)
Noncurrent Liabilities	(35,767)	(37)	(3,013)	443	(38,374)
Total MTM Derivative Contract Liabilities	(142,825)	(18,811)	(5,626)	10,459	(156,803)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 28,672	$ (16,276)	$ (5,626)	$ 4,661	$ 11,431

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 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		(6,055)
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		(64)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)		1,434
Changes in Fair Value Due to Market Fluctuations During the Period (c)		451
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		2,658
Total MTM Risk Management Contract Net Assets		28,672
Net Cash Flow & Fair Value Hedge Contracts		(16,276)
DETM Assignment (e)		(5,626)
Collateral Deposits		4,661
Ending Net Risk Management Assets at March 31, 2008	$	11,431

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/ liabilities 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 March 31, 2008
(in thousands)

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ (2,482)	$ (625)	$ (14)	$ -	$ -	$ -	$ (3,121)
Level 2 (b)	3,427	10,392	6,762	446	329	-	21,356
Level 3 (c)	(168)	809	(1,457)	(13)	(8)	-	(837)
Total	$ 777	$ 10,576	$ 5,291	$ 433	$ 321	$ -	$ 17,398
Dedesignated Risk Management Contracts (d)	2,503	3,220	3,194	1,244	1,113	-	11,274
Total MTM Risk Management Contract Net Assets	$ 3,280	$ 13,796	$ 8,485	$ 1,677	$ 1,434	$ -	$ 28,672

(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 forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. 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 March 31, 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
Three Months Ended March 31, 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	(8,025)	(1,097)	409	(8,713)
Reclassifications from AOCI for Cash Flow Hedges Settled	338	(203)	(233)	(98)
Ending Balance in AOCI March 31, 2008	$ (8,443)	$ 867	$ (78)	$ (7,654)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $9.9 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 March 31, 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:

Three Months Ended March 31, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$652	$780	$342	$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 $10.3 million.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
REVENUES		
Electric Generation, Transmission and Distribution	$ 555,478	$ 492,534
Sales to AEP Affiliates	236,848	178,894
Other - Affiliated	5,299	4,038
Other - Nonaffiliated	4,563	3,975
TOTAL	802,188	679,441
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	238,934	198,293
Purchased Electricity for Resale	34,577	24,854
Purchased Electricity from AEP Affiliates	32,516	20,966
Other Operation	89,882	102,987
Maintenance	48,697	59,148
Depreciation and Amortization	68,566	84,276
Taxes Other Than Income Taxes	51,578	48,385
TOTAL	564,750	538,909
OPERATING INCOME	237,438	140,532
Other Income (Expense):		
Interest Income	2,908	412
Carrying Costs Income	4,229	3,541
Allowance for Equity Funds Used During Construction	544	571
Interest Expense	(34,382)	(25,931)
INCOME BEFORE INCOME TAX EXPENSE	210,737	119,125
Income Tax Expense	72,910	39,864
NET INCOME	137,827	79,261
Preferred Stock Dividend Requirements	183	183
EARNINGS APPLICABLE TO COMMON STOCK	$ 137,644	$ 79,078

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 Three Months Ended March 31, 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			(183)		(183)
TOTAL					2,002,779
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,485				(6,471)	(6,471)
NET INCOME			79,261		79,261
TOTAL COMPREHENSIVE INCOME					72,790
MARCH 31, 2007	$ 321,201	$ 536,639	$ 1,280,963	$ (63,234)	$ 2,075,569
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			(183)		(183)
TOTAL					2,288,688
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,745				(8,811)	(8,811)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $379				703	703
NET INCOME			137,827		137,827
TOTAL COMPREHENSIVE INCOME					129,719
MARCH 31, 2008	$ 321,201	$ 536,640	$ 1,605,215	$ (44,649)	$ 2,418,407

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

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3,617	$ 6,666
Accounts Receivable:		
Customers	94,852	104,783
Affiliated Companies	121,141	119,560
Accrued Unbilled Revenues	36,275	26,819
Miscellaneous	22,113	1,578
Allowance for Uncollectible Accounts	(3,451)	(3,396)
Total Accounts Receivable	270,930	249,344
Fuel	96,984	92,874
Materials and Supplies	108,467	108,447
Risk Management Assets	112,774	44,236
Prepayments and Other	31,207	18,300
TOTAL	623,979	519,867
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	5,898,316	5,641,537
Transmission	1,073,766	1,068,387
Distribution	1,410,479	1,394,988
Other	370,583	318,805
Construction Work in Progress	531,974	716,640
Total	9,285,118	9,140,357
Accumulated Depreciation and Amortization	3,008,893	2,967,285
TOTAL - NET	6,276,225	6,173,072
OTHER NONCURRENT ASSETS		
Regulatory Assets	322,170	323,105
Long-term Risk Management Assets	55,460	49,586
Deferred Charges and Other	254,286	272,799
TOTAL	631,916	645,490
TOTAL ASSETS	$ 7,532,120	$ 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
March 31, 2008 and December 31, 2007
(Unaudited)

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 87,408	$ 101,548
Accounts Payable:		
General	156,776	141,196
Affiliated Companies	112,964	137,389
Short-term Debt – Nonaffiliated	-	701
Long-term Debt Due Within One Year – Nonaffiliated	137,225	55,188
Risk Management Liabilities	118,429	40,548
Customer Deposits	30,682	30,613
Accrued Taxes	200,688	185,011
Accrued Interest	37,532	41,880
Other	115,627	149,658
TOTAL	997,331	883,732
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,505,088	2,594,410
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	38,374	32,194
Deferred Income Taxes	937,500	914,170
Regulatory Liabilities and Deferred Investment Tax Credits	157,453	160,721
Deferred Credits and Other	243,402	229,635
TOTAL	4,081,817	4,131,130
TOTAL LIABILITIES	5,079,148	5,014,862
Minority Interest	17,938	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	1,605,215	1,469,717
Accumulated Other Comprehensive Income (Loss)	(44,649)	(36,541)
TOTAL	2,418,407	2,291,017
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,532,120	$ 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 Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 137,827	$ 79,261
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	68,566	84,276
Deferred Income Taxes	10,850	2,851
Carrying Costs Income	(4,229)	(3,541)
Allowance for Equity Funds Used During Construction	(544)	(571)
Mark-to-Market of Risk Management Contracts	(5,035)	980
Deferred Property Taxes	20,574	17,920
Change in Other Noncurrent Assets	(46,438)	(3,835)
Change in Other Noncurrent Liabilities	7,412	(4,434)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(21,586)	(38,070)
Fuel, Materials and Supplies	(4,130)	(19,684)
Accounts Payable	9,005	(25,807)
Customer Deposits	69	4,443
Accrued Taxes, Net	15,790	6,360
Accrued Interest	(4,348)	(2,986)
Other Current Assets	(13,020)	(3,528)
Other Current Liabilities	(19,146)	3,229
Net Cash Flows from Operating Activities	151,617	96,864
INVESTING ACTIVITIES		
Construction Expenditures	(142,257)	(301,635)
Change in Other Cash Deposits, Net	-	(7,988)
Proceeds from Sales of Assets	2,004	2,797
Net Cash Flows Used for Investing Activities	(140,253)	(306,826)
FINANCING ACTIVITIES		
Change in Short-term Debt, Net – Nonaffiliated	(701)	3,300
Change in Advances from Affiliates, Net	(14,140)	215,846
Retirement of Long-term Debt – Nonaffiliated	(7,463)	(7,463)
Funds from Amended Coal Contact	10,000	-
Principal Payments for Capital Lease Obligations	(1,926)	(1,902)
Dividends Paid on Cumulative Preferred Stock	(183)	(183)
Net Cash Flows from (Used for) Financing Activities	(14,413)	209,598
Net Decrease in Cash and Cash Equivalents	(3,049)	(364)
Cash and Cash Equivalents at Beginning of Period	6,666	1,625
Cash and Cash Equivalents at End of Period	$ 3,617	$ 1,261
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 37,491	$ 29,646
Net Cash Paid (Received) for Income Taxes	10,850	(8,899)
Noncash Acquisitions Under Capital Leases	687	608
Noncash Acquisition of Coal Land Rights	41,600	-
Construction Expenditures Included in Accounts Payable at March 31,	21,828	98,653

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.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments, Guarantees and Contingencies	Note 4
Benefit Plans	Note 6
Business Segments	Note 7
Income Taxes	Note 8
Financing Activities	Note 9

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

Results of Operations

First Quarter of 2008 Compared to First Quarter of 2007

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

First Quarter of 2007		$ (20)
Changes in Gross Margin:		
Retail and Off-system Sales Margins	14	
Transmission Revenues	1	
Other	10	
Total Change in Gross Margin		25
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(7)	
Deferral of Ice Storm Costs	80	
Depreciation and Amortization	(4)	
Taxes Other Than Income Taxes	(1)	
Other Income	4	
Interest Expense	(4)	
Total Change in Operating Expenses and Other		68
Income Tax Expense		(36)
First Quarter of 2008		$ 37

Net Income (Loss) increased $57 million in 2008. The key drivers of the increase were a $68 million decrease in Operating Expenses and Other and a $25 million increase in Gross Margin, partially offset by a $36 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 $14 million primarily due to:
  - A $15 million increase in retail sales margins mainly due to base rate adjustments during the year and a slight increase in KWH sales.

  This increase was offset by:
  - A $1 million decrease in off-system margins retained from a net decrease of $3 million from lower physical margins and lower trading margins.
- Other revenues increased $10 million primarily due to the recognition of the sale of SO_2 allowances. See "Oklahoma 2007 Ice Storms" section of Note 3.

Operating Expenses and Other decreased between years as follows:

- Other Operation and Maintenance expenses increased $7 million primarily due to:
  - A $10 million increase in production expenses primarily due to a write-off of pre-construction costs related to the cancelled Red Rock Generating Facility. See "Red Rock Generating Facility" section of Note 3.
  - An $8 million increase due to amortization of the ice storm Regulatory Asset. See "Oklahoma 2007 Ice Storms" section of Note 3.
  - A $3 million increase in transmission expense primarily due to an increase in transmission services from nonaffiliated utilities and SPP charges and fees.
  - A $2 million increase in distribution maintenance expense due to increased vegetation management activities to enhance customer reliability.

  This increase was partially offset by:
  - A $17 million decrease due to the $21 million ice storm repair costs expensed in the first quarter 2007 compared to the $4 million ice storm repair costs expensed in the first quarter 2008.
- Deferral of Ice Storm Costs in 2008 of $80 million results from an OCC order approving recovery of ice storm costs related to storms in January and December 2007. See "Oklahoma 2007 Ice Storms" section of Note 3.
- Depreciation and Amortization expenses increased $4 million primarily due to the amortization of regulatory assets related to the Lawton Settlement and the ice storm regulatory asset.
- Other Income increased $4 million primarily due to an increase in carrying charges related to the deferred ice storm costs and the Lawton Settlement.
- Interest Expense increased $4 million primarily due to increased long-term borrowings.
- Income Tax Expense increased $36 million primarily due to an increase in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 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 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 $600 thousand.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
REVENUES		
Electric Generation, Transmission and Distribution	$ 318,880	$ 290,080
Sales to AEP Affiliates	15,935	24,593
Other	1,185	640
TOTAL	336,000	315,313
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	153,205	142,515
Purchased Electricity for Resale	48,582	67,409
Purchased Electricity from AEP Affiliates	17,269	13,484
Other Operation	55,999	41,007
Maintenance	34,587	43,085
Deferral of Ice Storm Costs	(79,902)	-
Depreciation and Amortization	26,167	22,706
Taxes Other Than Income Taxes	10,952	10,294
TOTAL	266,859	340,500
OPERATING INCOME (LOSS)	69,141	(25,187)
Other Income (Expense):		
Other Income	2,487	646
Carrying Costs Income	1,634	-
Interest Expense	(14,941)	(11,383)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT)	58,321	(35,924)
Income Tax Expense (Credit)	20,922	(15,498)
NET INCOME (LOSS)	37,399	(20,426)
Preferred Stock Dividend Requirements	53	53
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 37,346	$ (20,479)

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

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 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		20,000			20,000
Preferred Stock Dividends			(53)		(53)
TOTAL					604,999
COMPREHENSIVE LOSS					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $24				45	45
NET LOSS			(20,426)		(20,426)
TOTAL COMPREHENSIVE LOSS					(20,381)
MARCH 31, 2007	$ 157,230	$ 250,016	$ 178,397	$ (1,025)	$ 584,618
DECEMBER 31, 2007	$ 157,230	$ 310,016	$ 174,539	$ (887)	$ 640,898
EITF 06-10 Adoption, Net of Tax of $596			(1,107)		(1,107)
Preferred Stock Dividends			(53)		(53)
TOTAL					639,738
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $24				45	45
NET INCOME			37,399		37,399
TOTAL COMPREHENSIVE INCOME					37,444
MARCH 31, 2008	$ 157,230	$ 310,016	$ 210,778	$ (842)	$ 677,182

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

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,435	$ 1,370
Advances to Affiliates	-	51,202
Accounts Receivable:		
Customers	42,505	74,330
Affiliated Companies	94,257	59,835
Miscellaneous	14,450	10,315
Total Accounts Receivable	151,212	144,480
Fuel	23,348	19,394
Materials and Supplies	48,823	47,691
Risk Management Assets	99,625	33,308
Accrued Tax Benefits	27,513	31,756
Margin Deposits	1,844	8,980
Prepayments and Other	18,297	18,137
TOTAL	372,097	356,318
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,170,963	1,110,657
Transmission	579,163	569,746
Distribution	1,369,834	1,337,038
Other	245,669	241,722
Construction Work in Progress	154,375	200,018
Total	3,520,004	3,459,181
Accumulated Depreciation and Amortization	1,187,333	1,182,171
TOTAL - NET	2,332,671	2,277,010
OTHER NONCURRENT ASSETS		
Regulatory Assets	197,860	158,731
Long-term Risk Management Assets	5,784	3,358
Deferred Charges and Other	75,678	48,454
TOTAL	279,322	210,543
TOTAL ASSETS	$ 2,984,090	$ 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
March 31, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 62,159	$ -
Accounts Payable:		
General	157,712	189,032
Affiliated Companies	79,293	80,316
Long-term Debt Due Within One Year – Nonaffiliated	33,700	-
Risk Management Liabilities	82,378	27,118
Customer Deposits	41,775	41,477
Accrued Taxes	36,238	18,374
Regulatory Liability for Over-Recovered Fuel Costs	16,269	11,697
Other	37,501	57,708
TOTAL	547,025	425,722
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	884,677	918,316
Long-term Risk Management Liabilities	4,382	2,808
Deferred Income Taxes	495,817	456,497
Regulatory Liabilities and Deferred Investment Tax Credits	314,622	338,788
Deferred Credits and Other	55,123	55,580
TOTAL	1,754,621	1,771,989
TOTAL LIABILITIES	2,301,646	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	310,016	310,016
Retained Earnings	210,778	174,539
Accumulated Other Comprehensive Income (Loss)	(842)	(887)
TOTAL	677,182	640,898
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,984,090	$ 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 Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income (Loss)	$ 37,399	$ (20,426)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows Used for Operating Activities:		
Depreciation and Amortization	26,167	22,706
Deferred Income Taxes	37,899	1,039
Deferral of Ice Storm Costs	(79,902)	-
Allowance for Equity Funds Used During Construction	(1,359)	(646)
Mark-to-Market of Risk Management Contracts	(11,881)	4,732
Deferred Property Taxes	(26,694)	(24,809)
Change in Other Noncurrent Assets	22,022	5,039
Change in Other Noncurrent Liabilities	(20,541)	(11,269)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(5,027)	16,116
Fuel, Materials and Supplies	(5,086)	(3,513)
Accounts Payable	(25,698)	6,941
Accrued Taxes, Net	22,107	(4,378)
Fuel Over/Under Recovery, Net	4,572	16,572
Other Current Assets	6,976	5,656
Other Current Liabilities	(20,759)	(31,462)
Net Cash Flows Used for Operating Activities	(39,805)	(17,702)
INVESTING ACTIVITIES		
Construction Expenditures	(73,203)	(61,301)
Change in Advances to Affiliates, Net	51,202	-
Other	148	(12)
Net Cash Flows Used for Investing Activities	(21,853)	(61,313)
FINANCING ACTIVITIES		
Capital Contribution from Parent	-	20,000
Change in Advances from Affiliates, Net	62,159	59,371
Principal Payments for Capital Lease Obligations	(383)	(370)
Dividends Paid on Cumulative Preferred Stock	(53)	(53)
Net Cash Flows from Financing Activities	61,723	78,948
Net Increase (Decrease) in Cash and Cash Equivalents	65	(67)
Cash and Cash Equivalents at Beginning of Period	1,370	1,651
Cash and Cash Equivalents at End of Period	$ 1,435	$ 1,584
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 12,380	$ 12,921
Net Cash Paid (Received) for Income Taxes	(19,408)	2,623
Noncash Acquisitions Under Capital Leases	135	283
Construction Expenditures Included in Accounts Payable at March 31,	21,086	19,038

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.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments, Guarantees and Contingencies	Note 4
Benefit Plans	Note 6
Business Segments	Note 7
Income Taxes	Note 8
Financing Activities	Note 9

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

Results of Operations

First Quarter of 2008 Compared to First Quarter of 2007

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

First Quarter of 2007		$	10
Changes in Gross Margin:			
Retail and Off-system Sales Margins (a)	4		
Transmission Revenues	1		
Other	(1)		
Total Change in Gross Margin			4
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(11)		
Depreciation and Amortization	(2)		
Taxes Other Than Income Taxes	(1)		
Other Income	2		
Interest Expense	(2)		
Total Change in Operating Expenses and Other			(14)
Income Tax Expense			5
First Quarter of 2008		$	5

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

Net Income decreased $5 million to $5 million in 2008. The key driver of the decrease was a $14 million increase in Operating Expenses and Other, offset by a $5 million decrease in Income Tax Expense and a $4 million increase in Gross Margin.

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 $4 million primarily due to:
  - A $3 million increase in retail sales margins related to higher fuel recovery with regards to wholesale customers.
  - A $2 million increase from lower sharing of net realized off-system sales margins.
- Other revenues decreased $1 million primarily due to a $6 million decrease in gains on sales of emission allowances partially offset by a $5 million increase in revenue from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to outside parties.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $11 million primarily due to:
  - A $6 million increase in operating expenses from SWEPCo's affiliated mining operations.
  - A $2 million increase in administrative and general expenses, primarily associated with outside services and employee-related expenses.
  - A $1 million increase in Maintenance expenses from planned and forced outages at the Welsh, Dolet Hills, Flint Creek, Knox Lee and Pirkey Plants.
- Depreciation and Amortization increased $2 million primarily due to higher depreciable asset balances.
- Other Income increased $2 million primarily due to an increase in the equity component of AFUDC as a result of new generation projects at the Turk Plant, Mattison Plant and Stall Unit.
- Interest Expense increased $2 million primarily due to higher interest of $3 million related to higher long-term debt partially offset by a $2 million increase in the debt component of AFUDC due to new generation projects at the Turk Plant, Mattison Plant and Stall Unit.
- Income Tax Expense decreased $5 million primarily due to a decrease in pretax book income and state income taxes.

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. For Senior Unsecured Debt, Fitch downgraded SWEPCo from A- to BBB+. Current ratings are as follows:

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

Cash Flow

Cash flows for the three months ended March 31, 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	(4,102)	65,590
Investing Activities	(125,877)	(120,639)
Financing Activities	134,140	54,331
Net Increase (Decrease) in Cash and Cash Equivalents	4,161	(718)
Cash and Cash Equivalents at End of Period	$ 5,903	$ 1,900

Operating Activities

Net Cash Flows Used for Operating Activities were $4 million in 2008. SWEPCo produced Net Income of $5 million during the period and had a noncash expense item of $36 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $40 million outflow from Fuel Over/Under Recovery, Net was the result of higher fuel costs. The $22 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $21 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes.

Net Cash Flows From Operating Activities were $66 million in 2007. SWEPCo produced Net Income of $10 million during the period and had a noncash expense item of $34 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 $36 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes. The $20 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 $126 million and $121 million, respectively. Construction Expenditures of $125 million and $108 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 2007, SWEPCo had a net increase of $9 million in loans to the Utility Money Pool. For the remainder of 2008, SWEPCo expects construction expenditures to be approximately $510 million.

Financing Activities

Cash Flows From Financing Activities were $134 million during 2008. SWEPCo received a Capital Contribution from Parent of $50 million. SWEPCo had a net increase of $88 million in borrowings from the Utility Money Pool.

Cash Flows From Financing Activities were $54 million during 2007. SWEPCo issued $250 million of Senior Unsecured Notes. SWEPCo had a net decrease of $189 million in borrowings from the Utility Money Pool.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2008 were:

Issuances

None

Retirements

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Nonaffiliated	$	1,101	4.47	2011
Notes Payable – Nonaffiliated		750	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.

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 March 31, 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 March 31, 2008 (in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 119,952	$ 160	$ -	$ (1,132)	$ 118,980
Noncurrent Assets	7,125	75	-	(26)	7,174
Total MTM Derivative Contract Assets	127,077	235	-	(1,158)	126,154
Current Liabilities	(113,496)	(6)	(91)	15,096	(98,497)
Noncurrent Liabilities	(6,167)	-	(105)	961	(5,311)
Total MTM Derivative Contract Liabilities	(119,663)	(6)	(196)	16,057	(103,808)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 7,414	$ 229	$ (196)	$ 14,899	$ 22,346

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 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		(1,643)
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)		326
Changes in Fair Value Due to Market Fluctuations During the Period (c)		(141)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		741
Total MTM Risk Management Contract Net Assets		7,414
Net Cash Flow & Fair Value Hedge Contracts		229
DETM Assignment (e)		(196)
Collateral Deposits		14,899
Ending Net Risk Management Assets at March 31, 2008	$	22,346

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/ liabilities 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 March 31, 2008
(in thousands)

	Remainder 2008	2009	2010	2011	2012	After 2012	Total
Level 1 (a)	$ 2,884	$ (283)	$ -	$ -	$ -	$ -	$ 2,601
Level 2 (b)	3,168	1,551	143	(14)	-	-	4,848
Level 3 (c)	(38)	1	2	-	-	-	(35)
Total	$ 6,014	$ 1,269	$ 145	$ (14)	$ -	$ -	$ 7,414

(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

SWEPCo is exposed to market fluctuations in energy commodity prices impacting power operations. Managment 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 forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. 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 March 31, 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
Three Months Ended March 31, 2008
(in thousands)

	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2007	$ (6,650)	$ 629	$ (6,021)
Changes in Fair Value	-	68	68
Reclassifications from AOCI for Cash Flow Hedges Settled	207	(544)	(337)
Ending Balance in AOCI March 31, 2008	$ (6,443)	$ 153	$ (6,290)

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 March 31, 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:

Three Months Ended March 31, 2008 (in thousands)				Twelve Months Ended December 31, 2007 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$84	$143	$52	$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 $4.3 million.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
REVENUES		
Electric Generation, Transmission and Distribution	$ 325,901	$ 327,284
Sales to AEP Affiliates	13,592	16,415
Other	300	400
TOTAL	339,793	344,099
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	117,661	111,987
Purchased Electricity for Resale	40,270	52,498
Purchased Electricity from AEP Affiliates	20,440	22,917
Other Operation	63,579	53,783
Maintenance	27,468	26,339
Depreciation and Amortization	36,136	34,122
Taxes Other Than Income Taxes	17,419	15,991
TOTAL	322,973	317,637
OPERATING INCOME	16,820	26,462
Other Income (Expense):		
Interest Income	877	705
Allowance for Equity Funds Used During Construction	3,063	1,391
Interest Expense	(17,142)	(15,490)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT) AND MINORITY INTEREST EXPENSE	3,618	13,068
Income Tax Expense (Credit)	(1,987)	2,621
Minority Interest Expense	995	842
NET INCOME	4,610	9,605
Preferred Stock Dividend Requirements	57	57
EARNINGS APPLICABLE TO COMMON STOCK	$ 4,553	$ 9,548

The common stock of SWEPCo is owned by a wholly-owned subsidiary of 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 Three Months Ended March 31, 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)
Preferred Stock Dividends			(57)		(57)
TOTAL					819,503
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $39				(327)	(327)
NET INCOME			9,605		9,605
TOTAL COMPREHENSIVE INCOME					9,278
MARCH 31, 2007	$ 135,660	$ 245,003	$ 467,244	$ (19,126)	$ 828,781
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		50,000			50,000
Preferred Stock Dividends			(57)		(57)
TOTAL					1,021,752
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $145				(269)	(269)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $127				235	235
NET INCOME			4,610		4,610
TOTAL COMPREHENSIVE INCOME					4,576
MARCH 31, 2008	$ 135,660	$ 380,003	$ 527,138	$ (16,473)	$ 1,026,328

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5,903	$ 1,742
Accounts Receivable:		
Customers	56,777	91,379
Affiliated Companies	41,862	33,196
Miscellaneous	14,213	10,544
Allowance for Uncollectible Accounts	(45)	(143)
Total Accounts Receivable	112,807	134,976
Fuel	77,463	75,662
Materials and Supplies	48,746	48,673
Risk Management Assets	118,980	39,850
Regulatory Asset for Under-Recovered Fuel Costs	22,868	5,859
Margin Deposits	2,229	10,650
Prepayments and Other	35,091	28,147
TOTAL	424,087	345,559
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,743,766	1,743,198
Transmission	743,285	737,975
Distribution	1,331,547	1,312,746
Other	633,446	631,765
Construction Work in Progress	546,248	451,228
Total	4,998,292	4,876,912
Accumulated Depreciation and Amortization	1,952,226	1,939,044
TOTAL - NET	3,046,066	2,937,868
OTHER NONCURRENT ASSETS		
Regulatory Assets	118,218	133,617
Long-term Risk Management Assets	7,174	4,073
Deferred Charges and Other	108,267	67,269
TOTAL	233,659	204,959
TOTAL ASSETS	$ 3,703,812	$ 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
March 31, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 89,210	$ 1,565
Accounts Payable:		
General	148,373	152,305
Affiliated Companies	67,172	51,767
Short-term Debt – Nonaffiliated	-	285
Long-term Debt Due Within One Year – Nonaffiliated	5,156	5,906
Risk Management Liabilities	98,497	32,629
Customer Deposits	37,788	37,473
Accrued Taxes	53,395	26,494
Regulatory Liability for Over-Recovered Fuel Costs	-	22,879
Other	72,623	76,554
TOTAL	572,214	407,857
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,140,303	1,141,311
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	5,311	3,334
Deferred Income Taxes	367,814	361,806
Regulatory Liabilities and Deferred Investment Tax Credits	327,117	334,014
Deferred Credits and Other	208,291	210,725
TOTAL	2,098,836	2,101,190
TOTAL LIABILITIES	2,671,050	2,509,047
Minority Interest	1,737	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	380,003	330,003
Retained Earnings	527,138	523,731
Accumulated Other Comprehensive Income (Loss)	(16,473)	(16,439)
TOTAL	1,026,328	972,955
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,703,812	$ 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 Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 4,610	$ 9,605
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	36,136	34,122
Deferred Income Taxes	3,804	(6,677)
Allowance for Equity Funds Used During Construction	(3,063)	(1,391)
Mark-to-Market of Risk Management Contracts	(14,231)	4,857
Deferred Property Taxes	(29,799)	(28,815)
Change in Other Noncurrent Assets	6,589	(1,807)
Change in Other Noncurrent Liabilities	(14,634)	(178)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	22,169	20,469
Fuel, Materials and Supplies	(1,874)	(4,141)
Accounts Payable	7,398	13,806
Accrued Taxes, Net	21,279	36,113
Fuel Over/Under Recovery, Net	(39,888)	4,212
Other Current Assets	7,683	11,381
Other Current Liabilities	(10,281)	(25,966)
Net Cash Flows from (Used for) Operating Activities	(4,102)	65,590
INVESTING ACTIVITIES		
Construction Expenditures	(125,358)	(107,613)
Change in Advances to Affiliates, Net	-	(8,959)
Other	(519)	(4,067)
Net Cash Flows Used for Investing Activities	(125,877)	(120,639)
FINANCING ACTIVITIES		
Capital Contribution from Parent	50,000	-
Issuance of Long-term Debt – Nonaffiliated	-	247,548
Change in Short-term Debt, Net – Nonaffiliated	(285)	3,290
Change in Advances from Affiliates, Net	87,645	(188,965)
Retirement of Long-term Debt – Nonaffiliated	(1,851)	(6,395)
Principal Payments for Capital Lease Obligations	(1,312)	(1,090)
Dividends Paid on Cumulative Preferred Stock	(57)	(57)
Net Cash Flows from Financing Activities	134,140	54,331
Net Increase (Decrease) in Cash and Cash Equivalents	4,161	(718)
Cash and Cash Equivalents at Beginning of Period	1,742	2,618
Cash and Cash Equivalents at End of Period	$ 5,903	$ 1,900
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 14,049	$ 16,747
Net Cash Paid for Income Taxes	641	580
Noncash Acquisitions Under Capital Leases	6,796	3,192
Construction Expenditures Included in Accounts Payable at March 31,	63,973	32,460

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.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments, Guarantees and Contingencies	Note 4
Benefit Plans	Note 6
Business Segments	Note 7
Income Taxes	Note 8
Financing Activities	Note 9

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Significant Accounting Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
2.	New Accounting Pronouncements	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
3.	Rate Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
4.	Commitments, Guarantees and Contingencies	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
5.	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 months March 31, 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 "FASB Staff Position 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

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 include 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 FASB Staff Position (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 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. 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 $286 thousand (net of tax of $154 thousand), $316 thousand (net of tax of $170 thousand) and $282 thousand (net of tax of $152 thousand), respectively, for the transition adjustment. SWEPCo's transition adjustment was a favorable $10 thousand (net of tax of $6 thousand) 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 March 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 14,644	$ 658,242	$ 9,808	$ (489,519)	$ 193,175
Cash Flow and Fair Value Hedges (a)	-	8,651	-	(2,796)	5,855
Dedesignated Risk Management Contracts (b)	-	-	-	16,113	16,113
Total Risk Management Assets	$ 14,644	$ 666,893	$ 9,808	$ (476,202)	$ 215,143
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 19,104	$ 628,849	$ 10,750	$ (493,696)	$ 165,007
Cash Flow and Fair Value Hedges (a)	-	26,298	-	(2,796)	23,502
DETM Assignment (c)	-	-	-	8,040	8,040
Total Risk Management Liabilities	$ 19,104	$ 655,147	$ 10,750	$ (488,452)	$ 196,549
Long-term Debt (e)	$ -	$ 49,714	$ -	$ -	$ 49,714
Total Liabilities	$ 19,104	$ 704,861	$ 10,750	$ (488,452)	$ 246,263

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

CSPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (f)	$ 52,589	$ -	$ -	$ 1,171	$ 53,760
Risk Management Assets:					
Risk Management Contracts (a)	$ 8,794	$ 374,975	$ 5,874	$ (279,296)	$ 110,347
Cash Flow and Fair Value Hedges (a)	-	3,544	-	(1,679)	1,865
Dedesignated Risk Management Contracts (b)	-	-	-	9,676	9,676
Total Risk Management Assets	$ 8,794	$ 378,519	$ 5,874	$ (271,299)	$ 121,888
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 11,473	$ 357,104	$ 6,426	$ (281,641)	$ 93,362
Cash Flow and Fair Value Hedges (b)	-	15,621	-	(1,679)	13,942
DETM Assignment (c)	-	-	-	4,829	4,829
Total Risk Management Liabilities	$ 11,473	$ 372,725	$ 6,426	$ (278,491)	$ 112,133

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

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 8,449	$ 348,611	$ 5,627	$ (258,654)	$ 104,033
Cash Flow and Fair Value Hedges (a)	-	3,617	-	(1,627)	1,990
Dedesignated Risk Management Contracts (b)	-	-	-	9,296	9,296
Total Risk Management Assets	$ 8,449	$ 352,228	$ 5,627	$ (250,985)	$ 115,319
Spent Nuclear Fuel and Decommissioning Trusts:					
Cash and Cash Equivalents (d)	$ -	$ 13,386	$ -	$ 10,286	$ 23,672
Debt Securities	343,078	491,865	-	-	834,943
Equity Securities	465,783	-	-	-	465,783
Total Spent Nuclear Fuel and Decommissioning Trusts	$ 808,861	$ 505,251	$ -	$ 10,286	$ 1,324,398
Total Assets	$ 817,310	$ 857,479	$ 5,627	$ (240,699)	$ 1,439,717
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 11,022	$ 331,435	$ 6,146	$ (260,756)	$ 87,847
Cash Flow and Fair Value Hedges (a)	-	15,022	-	(1,627)	13,395
DETM Assignment (c)	-	-	-	4,640	4,640
Total Risk Management Liabilities	$ 11,022	$ 346,457	$ 6,146	$ (257,743)	$ 105,882

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

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 10,246	$ 585,650	$ 7,039	$ (448,510)	$ 154,425
Cash Flow and Fair Value Hedges (a)	-	4,492	-	(1,957)	2,535
Dedesignated Risk Management Contracts (b)	-	-	-	11,274	11,274
Total Risk Management Assets	$ 10,246	$ 590,142	$ 7,039	$ (439,193)	$ 168,234
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 13,367	$ 564,294	$ 7,876	$ (453,171)	$ 132,366
Cash Flow and Fair Value Hedges (a)	-	20,768	-	(1,957)	18,811
DETM Assignment (c)	-	-	-	5,626	5,626
Total Risk Management Liabilities	$ 13,367	$ 585,062	$ 7,876	$ (449,502)	$ 156,803

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

PSO

Assets:	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Risk Management Assets:					
Risk Management Contracts (a)	$ 31,254	$ 429,634	$ 47	$ (355,526)	$ 105,409
Cash Flow and Fair Value Hedges (a)	-	-	-	-	-
Total Risk Management Assets	$ 31,254	$ 429,634	$ 47	$ (355,526)	$ 105,409
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 29,049	$ 425,533	$ 68	$ (368,056)	$ 86,594
Cash Flow and Fair Value Hedges (a)	-	-	-	-	-
DETM Assignment (c)	-	-	-	166	166
Total Risk Management Liabilities	$ 29,049	$ 425,533	$ 68	$ (367,890)	$ 86,760

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

SWEPCo

Assets:	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Risk Management Assets:					
Risk Management Contracts (a)	$ 36,861	$ 516,029	$ 68	$ (427,039)	$ 125,919
Cash Flow and Fair Value Hedges (a)	-	242	-	(7)	235
Total Risk Management Assets	$ 36,861	$ 516,271	$ 68	$ (427,046)	$ 126,154
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 34,260	$ 511,181	$ 103	$ (441,938)	$ 103,606
Cash Flow and Fair Value Hedges (a)	-	13	-	(7)	6
DETM Assignment (c)	-	-	-	196	196
Total Risk Management Liabilities	$ 34,260	$ 511,194	$ 103	$ (441,749)	$ 103,808

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FASB Staff Position 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 deposits-in-transit and accrued interest receivables to/from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(e) Amount represents the fair valued portion of long-term debt designated as a fair value hedge.

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

The following table sets forth a reconciliation primarily of changes in the fair value of net trading derivatives and other investments classified as level 3 in the fair value hierarchy:

Net Risk Management Assets (Liabilities)	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)	(657)	(414)	(391)	(176)	29	63
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	721	-	1,639	-	106
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(1,026)	(596)	(572)	(693)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,438	-	724	-	193	204
Balance as of March 31, 2008	$ (942)	$ (552)	$ (519)	$ (837)	$ (21)	$ (35)

(a) Included in revenues on the Condensed Statement of Income for the three months ended March 31, 2008.
(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.

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.

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 September 15, 2007. The adoption of this standard had an immaterial impact on the financial statements.

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 March 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 March 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 March 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 March 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 March 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 March 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 March 31, 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:

	March 31, 2008	
	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)	
APCo	$ 8,173	$ 12,351
CSPCo	4,900	7,245
I&M	4,701	6,803
OPCo	5,798	10,459
PSO	977	13,507
SWEPCo	1,158	16,057

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, liabilities and equity, emission allowances, leases, insurance, subsequent events 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.

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 Restructuring – Affecting CSPCo and OPCo

The current Ohio restructuring legislation permits CSPCo and OPCo to implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. The RSP plans include generation rates which are between PUCO approved rates and higher market rates. In April 2008, the Ohio legislature passed legislation which allows utilities to set prices by filing an Electric Security Plan along with the ability to simultaneously file a Market Rate Option. The PUCO would have authority to approve or modify the utility's request to set prices. Both alternatives would involve earnings tests monitored by the PUCO. The legislation still must be signed by the Ohio governor and will become law 90 days after the governor's signature. Management is analyzing the financial statement implications of the pending legislation on CSPCo's and OPCo's generation supply business, more specifically, whether the fuel management operations of CSPCo and OPCo meet the criteria for application of SFAS 71. The financial statement impact of the pending legislation will not be known until the PUCO acts on specific proposals made by CSPCo and OPCo. Management expects a PUCO decision in the fourth quarter of 2008.

2008 Generation Rider and Transmission Rider Rate Settlement – Affecting CSPCo and OPCo

On January 30, 2008, the PUCO approved under the RSPs a settlement agreement, among CSPCo, OPCo and other parties, related to an additional average 4% generation rate increase and transmission cost recovery rider ("TCRR") adjustments to recover additional governmentally-mandated costs including increased 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 increased PJM costs 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 adjust billings to reflect actual costs including carrying costs. 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 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 matter.

Customer Choice Deferrals – Affecting CSPCo and OPCo

CSPCo's and OPCo's restructuring settlement agreement, approved by the PUCO in 2000, allows CSPCo and OPCo to establish regulatory assets for customer choice implementation costs and related carrying costs in excess of $20 million each for recovery in the next general base rate filing for the distribution business. Through March 31, 2008, CSPCo and OPCo incurred $54 million and $55 million, respectively, of such costs and established regulatory assets for future recovery of $27 million each, net of equity carrying costs of $7 million for CSPCo and $8 million for OPCo. Management believes that these costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates. However, failure of the PUCO to ultimately approve recovery of such costs would have an adverse effect on results of operations and cash flows.

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 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, traditional rate making procedures would apply. 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 from approved orders of the PUCO.

Recent estimates of the cost to build the proposed IGCC plant are approximately $2.7 billion. In light of the Ohio Supreme Court's decision, CSPCo and OPCo will not start construction of the IGCC plant and will await the outcome of the ongoing legislative process in Ohio to determine if it provides sufficient assurance of cost recovery to warrant commencing construction.

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. The recovery will be accomplished by 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 $2 million of this regulatory liability to income for the quarter ended March 31, 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. If the PUCO approves a market price for 2008 below the 2007 price, it could have an adverse effect on future results of operations and cash flows. 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 off-system sales.

Virginia Rate Matters

Virginia Base Rate Filing – Affecting APCo

In March 2008, APCo filed a notice with the Virginia SCC that it plans to file a general base rate case no sooner than May 2008. The rate case will be based on a test year ending December 31, 2007, with adjustments through June 2008.

Virginia E&R Costs Recovery Filing – Affecting APCo

As of March 31, 2008, APCo has $85 million of deferred Virginia incremental E&R costs. Currently APCo is recovering $26 million of the deferral for incremental costs incurred through September 30, 2006. APCo intends to file in May 2008 for recovery of deferred incremental E&R costs incurred from October 1, 2006 through December 31, 2007 which totals $46 million. The remaining deferral will be requested in a 2009 filing. As of March 31, 2008, APCo has $21 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 addition, if the Virginia SCC were to disallow any additional portion of APCo's deferral, it would also have an adverse affect on future results of operations and cash flows.

Virginia Fuel Clause Filing – 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 back to June 1, 2007. The adjusted factor will increase 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 in the fourth quarter of 2008 to ensure accurate assignment of the prudently incurred PJM transmission line loss costs to APCo's Virginia jurisdictional operations. APCo 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 filed a notice of appeal to the Supreme Court of Virginia.

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 requests 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 March 31, 2008, APCo has deferred for future recovery pre-construction IGCC costs of $7 million applicable to Virginia. 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 on the basis of their 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. If necessary, APCo will seek recovery of its prudently incurred deferred pre-construction costs. If 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 itself, a $15 million increase in construction cost surcharges and $3 million of reliability expenditures, to become effective July 2008. 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 actuals and should have no earnings effect due to the deferral of any over/under-recovery of actual ENEC costs. However, if the WVPSC were to disallow the deferral of any costs including the incremental cost of PJM's recently revised costs associated with transmission line losses, it would have an adverse affect on future results of operations and cash flows. An order is expected by June 2008.

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, WV.

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. If APCo receives all necessary approvals, the plant could be completed as early as mid-2012. At the time of the filing, the cost of the plant was estimated at $2.2 billion. The Virginia SCC's decision to deny APCo's request to build an IGCC plant may have an impact on the project (See the "APCo's Virginia SCC Filing for an IGCC Plant" above). Through March 31, 2008, APCo deferred for future recovery pre-construction IGCC costs of $7 million applicable to the West Virginia jurisdiction and $2 million applicable to the FERC jurisdiction. If these 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 January 2008, I&M filed for an increase in its Indiana base rates of $82 million including a return on equity of 11.5%. The base rate increase includes a previously approved $69 million annual reduction in depreciation expense. 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 $46 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 in early 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 August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. In October 2007, the OCC 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. 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. PSO also filed prudence testimony in November 2007 covering the year 2006. The OCC staff and intervenors filed testimony in April 2008. Hearings are scheduled in May 2008. The only major issue raised in each of those proceedings was the alleged under allocation of off-system sales credits under the FERC-approved allocation agreements, which was determined not to be jurisdictional to the OCC. OCC orders applicable to both the 2005 and 2006 prudence proceedings are expected in 2008.

Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings and prudence reviews. 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.

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 denied PSO's and OG&E's applications for construction preapproval. The OCC stated that PSO failed to fully study other alternatives. 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. As a result of the OCC's decision, PSO will restudy various alternative options 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. A hearing on the settlement is scheduled for 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. Should the OCC not approve the settlement agreement and if recovery of the remaining regulatory asset becomes no longer probable or is denied, future results of operations and cash flows would be adversely affected by the write off of the remaining regulatory asset.

Oklahoma 2007 Ice Storms – Affecting PSO

In October 2007, PSO filed with the OCC requesting recovery of $13 million of operation and maintenance expenses 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 such expense and to amortize this 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 a December 2007 ice storm.

In February 2008, PSO entered into a settlement agreement for recovery of costs from both ice storms. In March 2008, the OCC approved the settlement subject to an audit of the final December ice storm costs to be 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 will 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.

<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. In April 2008, SWEPCo filed the first FRP anticipating that the LPSC would approve the settlement agreement. Based on the FRP, SWEPCo proposes to increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%.

If in years two or three 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. This separate credit rider will cease effective August 2011.

In addition, the settlement provides for a reduction in 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.

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 with 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. As of March 31, 2008, SWEPCo has capitalized pre-construction costs of $76 million and has contractual construction commitments of an additional $219 million. As of March 31, 2008, if the plant were to be cancelled, then cancellation fees of $59 million would terminate these construction commitments.

In March 2007, the PUCT approved SWEPCo's certificate for the facility. 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. 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. If SWEPCo 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.

Arkansas Rate Matters

Turk Plant – Affecting SWEPCo

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. Ultra-supercritical technology uses higher temperatures and higher pressures to produce electricity more efficiently – thereby using less fuel and providing substantial emissions reductions. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with the Oklahoma Municipal Power Authority (OMPA), the Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk Plant. The Turk Plant is 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. As of March 31, 2008, including the joint owners' share, SWEPCo capitalized approximately $313 million of expenditures and has significant contractual construction commitments for an additional $838 million. As of March 31, 2008, if the plant were to be cancelled, then cancellation fees of $67 million would terminate these construction commitments.

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. SWEPCo is still awaiting approvals from the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers. Both approvals are expected to be received by the third quarter of 2008. The PUCT held hearings in October 2007. In January 2008, a Texas ALJ issued a report, which concluded that SWEPCo failed to prove there was a need for the plant. The Texas ALJ recommended that SWEPCo's application be denied. The PUCT has voted to reopen the record and conduct additional hearings. SWEPCo expects a decision from the PUCT in the last half of 2008. In March 2008, the LPSC approved the application to construct the Turk Plant. If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. If SWEPCo cannot recover its costs, it could 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

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 AEP and ultimately its 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 $105 million of the $220 million of SECA revenues and will consume about $7 million of the reserve for refund, leaving approximately $115 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. AEP filed a Petition for Review of the FERC orders in this case in February 2008 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 to recover lost T&O revenues previously applied to reduce retail rates. 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 late 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, 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.

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. Management believes that the appropriate amount of revenues is being recognized. Multiple intervenors have protested or requested re-hearing of the order. Discovery and settlement discussions have begun. Management is unable to predict the outcome of this proceeding.

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, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At March 31, 2008, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, with maturities ranging from December 2008 to March 2009.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of March 31, 2008, SWEPCo collected approximately $35 million through a rider for final mine closure costs, which is recorded in Deferred Credits and Other on SWEPCo's 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

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 March 31, 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.

AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of 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 March 31, 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	$ 9
CSPCo	4
I&M	6
OPCo	9
PSO	5
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 has an initial term of five years. At the end of each lease term, AEP may (a) renew for another five-year term, not to exceed a total of twenty years; (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value; or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. AEP intends to renew the lease for the full remaining terms. This operating lease agreement allows AEP to avoid a large initial capital expenditure and to spread its railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment.

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 $46 million as of March 31, 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 $14 million ($9 million, net of tax) and SWEPCo's is approximately $16 million ($11 million, net of tax).

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. Cases are still pending that could affect CSPCo's share of jointly-owned units at Beckjord and Stuart stations. 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 and scheduled a settlement conference in May 2008. The Beckjord case is scheduled for a liability trial in May 2008. Beckjord is operated by Duke Energy Ohio, Inc.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, CSPCo might have for civil penalties under the pending CAA proceedings for its jointly-owned plants. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If 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 has been submitted to the Federal EPA and the DOJ for a 45-day comment period prior to entry.

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. TCEQ filed an amended Report during the fourth quarter of 2007, eliminating certain claims and reducing the recommended penalty amount to $122 thousand. 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. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration. In June 2007, TCEQ denied that motion. The permit alteration was appealed to the Travis County District Court, but would be resolved by entry of the consent decree in the federal citizen suit action. The District Court issued a stay while approval of the consent decree is pending.

On February 8, 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 early March 2008.

Management is unable to predict the timing of any future action by TCEQ, the Federal EPA or the special interest groups or the effect of such actions 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.

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 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 due May 2008. I&M cannot predict the cost of remediation or the amount of costs recoverable from third parties.

In those instances where AEP subsidiaries have been named a Potentially Responsible Party (PRP) or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

The Registrant Subsidiaries evaluate the potential liability for each Superfund site separately, but several general statements can be made regarding their potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for any of the identified Superfund sites.

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 and argued before the U.S. Supreme Court in February 2008. 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 table provides the components of AEP's net periodic benefit cost for the plans for the three months ended March 31, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 24	$ 10	$ 10
Interest Cost	63	59	28	26
Expected Return on Plan Assets	(84)	(85)	(28)	(26)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	9	15	3	3
Net Periodic Benefit Cost	$ 13	$ 13	$ 20	$ 20

The following table provides Registrant Subsidiaries' the net periodic benefit cost (credit) for the plans for the three months ended March 31, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
Company	2008	2007	2008	2007
	(in thousands)			
APCo	$ 835	$ 842	$ 3,699	$ 3,560
CSPCo	(349)	(257)	1,498	1,491
I&M	1,821	1,900	2,423	2,530
OPCo	319	245	2,816	2,802
PSO	508	424	1,387	1,431
SWEPCo	935	746	1,376	1,419

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.

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. Management continues to evaluate the impact of the law change, but does not expect the law change to have a material impact on results of operations, cash flows or financial condition.

On July 12, 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan's principal business tax. The new law was effective January 1, 2008 and replaced the Michigan Single Business Tax that expired at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

On September 30, 2007, the Governor of Michigan signed House Bill 5198, which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis difference triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15- year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. The Registrant Subsidiaries have evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect their 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 three months of 2008 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$ 500,000	7.00	2038

Company	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Other	$ 3	13.718	2026
CSPCo	Senior Unsecured Notes	52,000	6.51	2008
I&M	Pollution Control Bonds	45,000	Variable	2009
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
SWEPCo	Notes Payable	1,101	4.47	2011
SWEPCo	Notes Payable	750	Variable	2008

In April 2008, I&M issued $40 million of 5.25% Pollution Control Bonds due in 2025.

In April 2008, CSPCo remarketed its outstanding $44.5 million and $56 million Pollution Control Bonds, resulting in new interest rates of 4.85% and 5.10%, respectively. No proceeds were received related to these remarketings. The principal amounts of the Pollution Control Bonds are reflected in Long-term Debt on CSPCo's Condensed Consolidated Balance Sheet as of March 31, 2008.

In April 2008, SWEPCo remarketed its outstanding $81.7 million Pollution Control Bonds, resulting in a new interest rate of 4.95%. No proceeds were received related to this remarketing. The principal amount of the Pollution Control Bonds is reflected in Long-term Debt on SWEPCo's Condensed Consolidated Balance Sheet as of March 31, 2008.

In April 2008, APCo repurchased its $40 million and $30 million of variable rate interest Pollution Control Bonds, each due in 2019, and $17.5 million variable rate interest Pollution Control Bonds due in 2021.

In April 2008, CSPCo repurchased its $48.6 million of variable rate interest Pollution Control Bonds due in 2038.

As of March 31, 2008, the Registrant Subsidiaries had tax-exempt long-term debt (Pollution Control Bonds) sold at auction rates that are reset every 7, 28 or 35 days. This debt is insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation, Financial Guaranty Insurance Co., MBIA Insurance Corporation and XL Capital Assurance Inc. The amounts outstanding by Registrant Subsidiary are as follows:

	As of March 31, 2008
	(in millions)
APCo	$ 213
CSPCo	193
I&M	167
OPCo	468
PSO	34
SWEPCo	176

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 the Registrant Subsidiaries' 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. During the first quarter of 2008, the Registrant Subsidiaries reduced their outstanding auction rate securities by redeeming or repurchasing $95 million of such debt securities. In April 2008, they converted, refunded or provided notice to convert or refund $779 million of the outstanding auction rate securities. Management plans to continue this conversion and refunding process for the remaining $471 million to other permitted modes, including term-put and fixed-rate structures through the third quarter of 2008. The conversions will likely result in higher interest charges compared to prior year but lower than the failed auction rates for this tax-exempt long-term debt.

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 March 31, 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 three months ended March 31, 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 March 31, 2008	Authorized Short-Term Borrowing Limit
	(in thousands)					
APCo	$ 307,226	$ 269,987	$ 261,154	$ 264,528	$ 261,823	$ 600,000
CSPCo	195,038	-	139,127	-	(163,999)	350,000
I&M	239,125	-	102,772	-	(185,938)	500,000
OPCo	201,263	-	102,902	-	(87,408)	600,000
PSO	62,159	59,384	20,089	30,664	(62,159)	300,000
SWEPCo	89,210	-	48,654	-	(89,210)	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Three Months Ended March 31,	
	2008	2007
Maximum Interest Rate	5.37%	5.43%
Minimum Interest Rate	3.39%	5.30%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 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 Three Months Ended March 31,		Average Interest Rate for Funds Loaned to the Utility Money Pool for the Three Months Ended March 31,	
Company	**2008**	**2007**	**2008**	**2007**
APCo	4.21%	5.34%	3.46%	-%
CSPCo	4.01%	5.35%	-%	5.33%
I&M	3.99%	5.34%	-%	-%
OPCo	4.29%	5.34%	-%	-%
PSO	3.51%	5.34%	4.57%	-%
SWEPCo	4.00%	5.35%	-%	5.34%

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		March 31, 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	-	- %	285	5.25 %

Credit Facilities

In April 2008, the Parent, the AEP East companies and the AEP West companies entered into a $650 million 3-year credit agreement with a third party. Concurrently, the Parent, the AEP East companies and the AEP West companies also entered into a $350 million 364-day credit agreement with a third party.

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.

Significant Factors

Ohio Restructuring

The current Ohio restructuring legislation permits CSPCo and OPCo to implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. The RSP plans include generation rates which are between PUCO approved rates and higher market rates. In April 2008, the Ohio legislature passed legislation which allows utilities to set prices by filing an Electric Security Plan along with the ability to simultaneously file a Market Rate Option. The PUCO would have authority to approve or modify the utility's request to set prices. Both alternatives would involve earnings tests monitored by the PUCO. The legislation still must be signed by the Ohio governor and will become law 90 days after the governor's signature. Management is analyzing the financial statement implications of the pending legislation on CSPCo's and OPCo's generation supply business, more specifically, whether the fuel management operations of CSPCo and OPCo meet the criteria for application of SFAS 71. The financial statement impact of the pending legislation will not be known until the PUCO acts on specific proposals made by CSPCo and OPCo. Management expects a PUCO decision in the fourth quarter of 2008.

New Generation

AEP is in various stages of construction of the following generation facilities. Certain plants are pending regulatory approval:

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	$ 58	-	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	59	$ 57	Gas	Simple-cycle	170	2008
AEGCo	Dresden (d)	Ohio	305 (d)	101	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	378	76	Gas	Combined-cycle	500	2010
SWEPCo	Turk (e)	Arkansas	1,522 (e)	313	Coal	Ultra-supercritical	600 (e)	2012
APCo	Mountaineer	West Virginia	2,230	-	Coal	IGCC	629	2012
CSPCo/OPCo	Great Bend	Ohio	2,700 (f)	-	Coal	IGCC	629	2017

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) 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.
(e) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals. See "Turk Plant" section below.
(f) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO. See "Ohio IGCC Plant" section of Note 3.

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 facility. 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. As of March 31, 2008, including the joint owners' share, SWEPCo capitalized approximately $313 million of expenditures and has significant contractual construction commitments for an additional $838 million. As of March 31, 2008, if the plant were to be cancelled, then cancellation fees of $67 million would terminate these construction commitments.

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. SWEPCo is still awaiting permit approvals from the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers. Both permits are expected to be received by the third quarter of 2008. The PUCT held hearings in October 2007. In January 2008, a Texas ALJ issued a report, which concluded that SWEPCo failed to prove there was a need for the plant. The Texas ALJ recommended that SWEPCo's application be denied. The PUCT has voted to reopen the record and conduct additional hearings. SWEPCo expects a decision from the PUCT in the last half of 2008. In March 2008, the LPSC approved the certificate to construct the Turk Plant. If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. If SWEPCo cannot recover its costs, it could have an adverse effect on future results of operations, cash flows and possibly financial condition.

APCo's IGCC Plant

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, WV. 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 July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover pre-construction and future construction financing costs associated with the IGCC plant.

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.

The Virginia SCC issued an order in April 2008 denying APCo's requests on the basis of their belief that the estimated cost may be significantly understated. The Virginia SCC also expressed concern that the $2.2 billion estimated cost of the IGCC plant did not include a retrofitting of carbon capture and sequestration facilities. In April 2008, APCo filed a petition for reconsideration in Virginia. If necessary, APCo will seek recovery of its prudently incurred deferred pre-construction costs.

Through March 31, 2008, APCo deferred for future recovery pre-construction IGCC costs of $16 million. If these deferred costs are not recoverable, 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 also monitors 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. Litigation continues against two plants CSPCo jointly-owns with Duke and DP&L, which they operate. Management is unable to predict the outcome of these cases. 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 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 include 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 FASB Staff Position (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 $286 thousand (net of tax of $154 thousand), $316 thousand (net of tax of $170 thousand) and $282 thousand (net of tax of $152 thousand), respectively, for the transition adjustment. SWEPCo's transition adjustment was a favorable $10 thousand (net of tax of $6 thousand) 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 September 15, 2007. The adoption of this standard had an immaterial impact on the Registrant Subsidiaries' financial statements.

In April 2007, the FASB issued FASB Staff Position 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 "FASB Staff Position 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 first 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 March 31, 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 first 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.

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 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.

Risks Relating to State Restructuring

In Ohio, our future rates are uncertain. *(Applies to AEP, OPCo and CSPCo.)*

The current Ohio restructuring legislation permits CSPCo and OPCo to implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. The RSP plans include generation rates which are between PUCO approved rates and higher market rates. In April 2008, the Ohio legislature passed legislation which allows utilities to set prices by filing an Electric Security Plan along with the ability to simultaneously file a Market Rate Option. The PUCO would have authority to approve or modify the utility's request to set prices. Both alternatives would involve earnings tests monitored by the PUCO. The legislation still must be signed by the Ohio governor and will become law 90 days after the governor's signature. Management is analyzing the financial statement implications of the pending legislation on CSPCo's and OPCo's generation supply business, more specifically, whether the fuel management operations of CSPCo and OPCo meet the criteria for application of SFAS 71. The financial statement impact of the pending legislation will not be known until the PUCO acts on specific proposals made by CSPCo and OPCo. Management expects a PUCO decision in the fourth quarter of 2008. A return to full cost-based regulation could have an adverse impact on the financial condition, future results of operations and cash flows of CSPCo and OPCo.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended March 31, 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
01/01/08 – 01/31/08	-	$ -	-	$ -
02/01/08 – 02/29/08	-	-	-	-
03/01/08 – 03/31/08	-	-	-	-

Item 5. Other Information

NONE

Item 6. Exhibits

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: May 1, 2008