AMERICAN ELECTRIC POWER CO INC
Form 10-Q
May 04, 2007

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, 2007**
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
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
0-346	AEP TEXAS CENTRAL COMPANY (A Texas Corporation)	74-0550600
0-340	AEP TEXAS NORTH COMPANY (A Texas Corporation)	75-0646790
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
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
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, or a non-accelerated filer. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer X Accelerated filer Non-accelerated filer

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are large accelerated filers, accelerated filers, or non-accelerated filers. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer Accelerated filer Non-accelerated filer X

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act.)
Yes No X

AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky 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, 2007
AEP Generating Company	1,000
	($1,000 par value)
AEP Texas Central Company	2,211,678
	($25 par value)
AEP Texas North Company	5,488,560
	($25 par value)
American Electric Power Company, Inc.	398,766,908
	($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)
Kentucky Power Company	1,009,000
	($50 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, 2007

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky 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
ADITC	Accumulated Deferred Investment Tax Credits.
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 domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP System Power Pool or 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 West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income (Loss).
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. AEPSC acts as the agent.
CTC	Competition Transition Charge.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
ECAR	East Central Area Reliability Council.
EDFIT	Excess Deferred Federal Income Taxes.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.

Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, “Consolidation of Variable Interest Entities.”
FIN 48	FASB Interpretation No. 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.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
IPP	Independent Power Producer.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System’s Nonutility Money Pool.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
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; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
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.
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.”
SFAS 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”
SFAS 158	Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.”
SFAS 159	Statement of Financial Accounting Standards No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities.”
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
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.
Transmission Equalization Agreement	Transmission Equalization Agreement by and among APCo, CSPCo, I&M, KPCo and OPCo with AEPSC as agent, promoting the allocation of the cost of ownership and operation of the transmission system in proportion to their demand ratios.
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.
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, costs and transportation for fuels and the creditworthiness 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 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 for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and 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.
- 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 and other energy-related commodities.
- Changes in utility regulation, including recent legislation in Virginia, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- 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.

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

EXECUTIVE OVERVIEW

Regulatory Activity

Our significant regulatory activities in 2007 are updated to include:

- In March 2007, the Texas District Court judge reversed his earlier preliminary decision and concluded the sale of assets method used by TCC to value its nuclear plant stranded costs was appropriate.
- In March 2007, various intervenors and the PUCT staff filed their recommendations in TCC's and TNC's energy delivery base rate filings. Though the recommendations varied, the range of recommended increase was $8 million to $30 million for TCC and $1 million to $14 million for TNC. In April 2007, TCC and TNC filed rebuttal testimony and continue to pursue $70 million and $22 million, respectively, in annual base rate increases. Hearings began in April 2007 and are scheduled to conclude in May 2007.
- In April 2007, the Virginia legislature approved amendments recommended by the Governor to the legislature's recently adopted, comprehensive bill providing for the re-regulation of electric utilities generation/supply rates. The effective date of the new amendments is July 1, 2007.
- In March 2007, a Hearing Examiner (HE) in Virginia issued a report recommending a $76 million increase in APCo's base rates and $45 million credit to the fuel factor for off-system sales margins. APCo continues to pursue an annual base rate increase of $225 million and a $27 million credit for off-system sales margins. We expect a ruling during 2007.
- In April 2007, the FERC issued an order reversing an initial favorable ALJ decision which had found the existing PJM zonal rate design to be unjust and determined that it should be replaced. In the April 2007 order, the FERC ruled that the existing PJM rate design is just and reasonable. As a result of this order, our retail customers will be asked to bear the full cost of the existing AEP east transmission zone facilities. We presently recover approximately 85% of these costs from retail customers. The FERC further ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants.
- In March 2007, the OCC staff and various intervenors filed testimony in PSO's base rate case. The recommendations were base rate reductions that ranged from $18 million to $52 million. In April 2007, PSO filed rebuttal testimony and continues to pursue an increase in annual base rates of $48 million.
- Beginning with the May 2007 billing cycle, CSPCo and OPCo implemented rates filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs. These increases are subject to refund until the PUCO issues a final order in the matter. The hearing is scheduled to begin in late May 2007.
- In March 2007, CSPCo filed an application under the 4% provision of the RSP to adjust the Power Acquisition Rider (PAR) which was authorized in 2005 by the PUCO in connection with CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio. If approved, CSPCo's revenues would increase by $22 million and $38 million for 2007 and 2008, respectively.
- In April 2007, CSPCo and OPCo filed a joint motion with the PUCO staff and other intervenors to withdraw the proposed enhanced reliability plan.

Investment Activity

Our significant investment activities in 2007 are updated to include:

- We completed the 480 MW Darby Electric Generation Station acquisition in April 2007.
- In April 2007, we signed a memorandum of understanding with Allegheny Energy Inc. to form a joint venture company to build and own certain electric transmission assets within PJM with the initial focus on a transmission line between AEP's Amos power plant in West Virginia and Allegheny's proposed Kemptown power plant in Maryland. We expect to execute definitive agreements for the joint venture with Allegheny Energy Inc. by mid-2007 and anticipate the joint venture will begin activities in the second half of 2007.

RESULTS OF OPERATIONS

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 34 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and Lower Mississippi rivers. Approximately 35% of the barging operations relates to the transportation of coal, 28% relates to agricultural products, 21% relates to steel and 16% relates to other commodities.

Generation and Marketing
- IPPs, wind farms and marketing and risk management activities primarily in ERCOT.

The table below presents our consolidated Income Before Discontinued Operations for the three months ended March 31, 2007 and 2006 (Earnings and Weighted Average Number of Basic Shares Outstanding in millions). We reclassified prior year amounts to conform to the current year's segment presentation.

	Three Months Ended March 31,			
	2007		2006	
	Earnings	EPS (b)	Earnings	EPS (b)
Utility Operations	$ 253	$ 0.63	$ 365	$ 0.93
MEMCO Operations	15	0.04	21	0.05
Generation and Marketing	(1)	-	4	0.01
All Other (a)	4	0.01	(12)	(0.03)
Income Before Discontinued Operations	$ 271	$ 0.68	$ 378	$ 0.96
Weighted Average Number of Basic Shares Outstanding		397		394

(a) All Other includes:

- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
-

Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in the fourth quarter of 2006.

(b) The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct equity interest in AEP's assets and liabilities as a whole.

First Quarter of 2007 Compared to First Quarter of 2006

Income Before Discontinued Operations in 2007 decreased $107 million compared to 2006 primarily due to a decrease in Utility Operations segment earnings of $112 million. The decrease in Utility Operations segment earnings primarily relates to higher operation and maintenance expenses, higher regulatory amortization expense, lower earnings-sharing payments from Centrica, lower off-system sales margins and the elimination of SECA revenues. These decreases were partially offset by higher retail margins related to new rates in the east region and favorable weather.

Average basic shares outstanding increased to 397 million in 2007 from 394 million in 2006 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 398 million as of March 31, 2007.

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, 2007	2006
	(in millions)	
Revenues	$ 3,033	$ 2,966
Fuel and Purchased Power	1,119	1,126
Gross Margin	1,914	1,840
Depreciation and Amortization	383	340
Other Operating Expenses	991	836
Operating Income	540	664
Other Income, Net	18	41
Interest Charges and Preferred Stock Dividend Requirements	179	154
Income Tax Expense	126	186
Income Before Discontinued Operations	$ 253	$ 365

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three Months Ended March 31, 2007 and 2006

	2007	2006
Energy Summary	(in millions of KWH)	
Retail:		
Residential	14,139	12,938
Commercial	9,359	8,909

Industrial	13,565	13,222
Miscellaneous	614	618
Total Retail	37,677	35,687
Wholesale	8,778	10,844
Texas Wires Delivery	5,831	5,546
Total KWHs	52,286	52,077

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, 2007 and 2006 were as follows:

	2007	**2006**
Weather Summary	**(in degree days)**	
Eastern Region		
Actual - Heating (a)	1,816	1,456
Normal - Heating (b)	1,792	1,817
Actual - Cooling (c)	14	1
Normal - Cooling (b)	3	3
Western Region (d)		
Actual - Heating (a)	902	658
Normal - Heating (b)	959	972
Actual - Cooling (c)	56	43
Normal - Cooling (b)	18	17

(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 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Income from Utility Operations Before Discontinued Operations
(in millions)

First Quarter of 2006		$ 365
Changes in Gross Margin:		
Retail Margins	139	
Off-system Sales	(41)	
Transmission Revenues	(29)	

Other Revenues	5	
Total Change in Gross Margin		74
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(111)	
Gain on Dispositions of Assets, Net	(47)	
Depreciation and Amortization	(43)	
Carrying Costs Income	(22)	
Other Income, Net	2	
Interest and Other Charges	(25)	
Total Change in Operating Expenses and Other		(246)
Income Tax Expense		60
First Quarter of 2007		$ 253

Income from Utility Operations Before Discontinued Operations decreased $112 million to $253 million in 2007. The key driver of the decrease was a $246 million increase in Operating Expenses and Other offset by a $74 million increase in Gross Margin and a $60 million decrease in Income Tax Expense.

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

- Retail Margins increased $139 million primarily due to the following:
  - A $35 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs and a $58 million increase related to new rates implemented in other east jurisdictions of Kentucky, West Virginia and Virginia. See “APCo Virginia Base Rate Case” in Note 3 for discussion of the Virginia increase implemented subject to refund.
  - A $34 million increase related to increased residential and commercial usage and customer growth.
  - A $40 million increase in usage related to weather. As compared to the prior year, our eastern region and western region experienced 25% and 37% increases, respectively, in heating degree days.

  These increases were partially offset by:
  - A $27 million decrease in financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market.
- Margins from Off-system Sales decreased $41 million primarily due to lower generation availability in the east due to planned outages for completion of environmental retrofits and higher retail load offset by higher margins from trading activities.
- Transmission Revenues decreased $29 million primarily due to the elimination of SECA revenues as of April 1, 2006. See the “Transmission Rate Proceedings at the FERC” section of Note 3.

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

- Other Operation and Maintenance expenses increased $111 million primarily due to increases in generation expenses related to plant outages and removal costs, distribution expenses associated with service reliability and storm restoration primarily in Oklahoma and expenses associated with employee benefits.

- Gain on Disposition of Assets, Net decreased $47 million primarily related to the earnings sharing agreement with Centrica from the sale of our REPs in 2002. In 2006, we received $70 million from Centrica for earnings sharing and in 2007 we received $20 million as the earnings sharing agreement ended.
- Depreciation and Amortization expense increased $43 million primarily due to increased Ohio regulatory asset amortization related to recovery of IGCC preconstruction costs, increased Texas amortization of the securitized transition assets, increased Virginia regulatory amortization related to environmental and reliability recovery and higher depreciable property balances.
- Carrying Costs Income decreased $22 million because TCC started recovering Texas stranded costs in October 2006, resulting in lower Texas carrying costs income in 2007.
- Interest and Other Charges increased $25 million primarily due to additional debt issued in the fourth quarter of 2006 partially offset by an increase in allowance for borrowed funds used for construction.
- Income Tax Expense decreased $60 million due to a decrease in pretax income.

MEMCO Operations

First Quarter of 2007 Compared to First Quarter of 2006

Income Before Discontinued Operations from our MEMCO Operations segment decreased from $21 million in 2006 to $15 million in 2007. The decrease was primarily related to a return to normal winter river operating conditions in 2007 compared to milder and more favorable weather in 2006 and lower spot market rates due to decreased barging demand caused by lower backhaul imports.

Generation and Marketing

First Quarter of 2007 Compared to First Quarter of 2006

Loss Before Discontinued Operations from our Generation and Marketing segment was $1 million in 2007 compared to income of $4 million in 2006. The decrease primarily relates to planned and forced outages at our Oklaunion plant in 2007 that limited the availability of power under lease.

All Other

First Quarter of 2007 Compared to First Quarter of 2006

Income Before Discontinued Operations from All Other increased from a $12 million loss in 2006 to income of $4 million in 2007. In 2006, we had after-tax losses of $8 million in 2006 from operation of the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. In 2007, we had an after-tax gain of $10 million on the sale of investment securities.

AEP System Income Taxes

Income Tax Expense decreased $59 million primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	March 31, 2007		December 31, 2006	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 13,902	58.7%	$ 13,698	59.1%
Short-term Debt	175	0.7	18	0.0
Total Debt	14,077	59.4	13,716	59.1
Common Equity	9,540	40.3	9,412	40.6
Preferred Stock	61	0.3	61	0.3
Total Debt and Equity Capitalization	$ 23,678	100.0%	$ 23,189	100.0%

Our ratio of debt to total capital increased from 59.1% to 59.4% in 2007 due to our increased borrowings.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At March 31, 2007, our available liquidity was approximately $3.1 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,500	April 2012
Total	3,000	
Cash and Cash Equivalents	259	
Total Liquidity Sources	3,259	
Less: AEP Commercial Paper Outstanding	150	
Letters of Credit Drawn	27	
Net Available Liquidity	$ 3,082	

In 2007, we amended the terms and extended the maturity of our two credit facilities by one year to March 2011 and April 2012, respectively. 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.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At March 31, 2007, this contractually-defined percentage was 54.5%. Nonperformance of these covenants could result in an event of default under these credit agreements. At March 31, 2007, 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 two revolving credit facilities do not permit the lenders to refuse a draw on either facility if a material adverse change occurs.

Under a regulatory order, our utility subsidiaries, other than TCC, cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% of its capital. In addition, this order restricts those utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At March 31, 2007, all applicable utility subsidiaries complied with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At March 31, 2007, we had not exceeded those authorized limits.

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2007 and AEP is currently on a stable outlook by the rating agencies. 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.

<u>Cash Flow</u>

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

	Three Months Ended March 31, 2007	**2006**
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 301	$ 401
Net Cash Flows From Operating Activities	351	583
Net Cash Flows Used For Investing Activities	(628)	(750)
Net Cash Flows From Financing Activities	235	42
Net Decrease in Cash and Cash Equivalents	(42)	(125)
Cash and Cash Equivalents at End of Period	$ 259	$ 276

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. 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, 2007, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2007 was $150 million. The weighted-average interest rate of our commercial paper during 2007 was 5.43%. 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 common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders. See the discussion below for further detail related to the components of our cash flows.

Operating Activities

	Three Months Ended March 31, 2007	2006
	(in millions)	
Net Income	$ 271	$ 381
Less: Discontinued Operations, Net of Tax	-	(3)
Income Before Discontinued Operations	271	378
Noncash Items Included in Earnings	420	323
Changes in Assets and Liabilities	(340)	(118)
Net Cash Flows From Operating Activities	$ 351	$ 583

Net Cash Flows From Operating Activities decreased in 2007 primarily due to lower fuel costs recovery.

Net Cash Flows From Operating Activities were $351 million in 2007 consisting primarily of Income Before Discontinued Operations of $271 million. Income Before Discontinued Operations included noncash expense items primarily for depreciation, amortization, deferred taxes and deferred investment tax credits. 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 these asset and liability accounts relates to a number of items, none of which were significant.

Net Cash Flows From Operating Activities were $583 million in 2006. We produced Income Before Discontinued Operations of $378 million. Income Before Discontinued Operations included noncash expense items primarily for depreciation, amortization, deferred taxes and deferred investment tax credits. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. Under-recovered fuel costs decreased due to recovery of higher cost of fuel, especially natural gas. 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 these asset and liability accounts relates to a number of items; the most significant are a $99 million cash increase from net Accounts Receivable/Accounts Payable due to a lower balance of Customer Accounts Receivable at March 31, 2006 and an increase in Accrued Taxes of $176 million. We did not make a federal income tax payment during the first quarter of 2006.

Investing Activities

	Three Months Ended March 31, 2007	2006
	(in millions)	
Construction Expenditures	$ (907)	$ (765)
Change in Other Temporary Cash Investments, Net	(20)	27

(Purchases)/Sales of Investment Securities, Net		236		(89)
Proceeds from Sales of Assets		68		111
Other		(5)		(34)
Net Cash Flows Used for Investing Activities	$	(628)	$	(750)

Net Cash Flows Used For Investing Activities were $628 million in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan. In our normal course of business, we purchase investment securities including auction rate securities and variable rate demand notes with cash available for short-term investments. Also included in Purchases/Sales of Investment Securities, Net are purchases and sales of securities within our nuclear trusts.

Net Cash Flows Used For Investing Activities were $750 million in 2006 primarily due to Construction Expenditures. Construction Expenditures increased due to our environmental investment plan.

We forecast approximately $2.6 billion of construction expenditures for the remainder of 2007 plus $427 million for announced purchases of gas-fired generating units. 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,			
		2007		**2006**
	(in millions)			
Issuance of Common Stock	$	54	$	5
Issuance/Retirement of Debt, Net		355		129
Dividends Paid on Common Stock		(155)		(146)
Other		(19)		54
Net Cash Flows From Financing Activities	$	235	$	42

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. We paid common stock dividends of $155 million. See Note 9 for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows From Financing Activities in 2006 were $42 million. During the first quarter of 2006, we issued $50 million of obligations relating to pollution control bonds and increased our short-term commercial paper outstanding. The Other amount of $54 million in the above table primarily consists of $68 million received from a coal supplier related to a long-term coal purchase contract amended in March 2006.

In April 2007, OPCo issued $400 million of three-year floating rate notes at an initial rate of 5.53% due in 2010. The proceeds from this issuance will contribute to our investment in environmental equipment.

Our capital investment plans for 2007 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, 2007		December 31, 2007	
	(in millions)			
AEP Credit Accounts Receivable Purchase Commitments	$	549	$	536
Rockport Plant Unit 2 Future Minimum Lease Payments		2,364		2,364
Railcars Maximum Potential Loss From Lease Agreement		31		31

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 2006 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2006 Annual Report and has not changed significantly from year-end other than the debt issuances discussed in “Cash Flow” and “Financing Activities” above.

Other

Texas REPs

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. We received $20 million and $70 million payments in 2007 and 2006, respectively, for our share in earnings. The payment we received in 2007 was the final payment under the earnings sharing agreement.

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 2006 Annual Report. The 2006 Annual Report should be read in conjunction with this report in order to understand significant factors without material changes in status since the issuance of our 2006 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition.

Electric Transmission Texas LLC Joint Venture

In January 2007, we signed a participation agreement with MidAmerican Energy Holdings Company (MidAmerican) to form a joint venture company, Electric Transmission Texas LLC (ETT), to fund, own and operate electric transmission assets in ERCOT. ETT filed with the PUCT in January 2007 requesting regulatory approval to operate as an electric transmission utility in Texas, to transfer from TCC to ETT approximately $76 million of transmission assets currently under construction and to establish a wholesale transmission tariff for ETT. ETT also requested approval from the PUCT of initial rates based on an 11.25% return on equity. A procedural schedule has been established in the case, with a hearing scheduled for June. We expect a final order from the PUCT in the third quarter.

TCC also made a regulatory filing at the FERC in February 2007 regarding the transfer of certain transmission assets from TCC to ETT. In April, the FERC authorized the transfer.

Upon receipt of all required regulatory approvals, AEP Utilities, Inc., a subsidiary of AEP, and MEHC Texas Transco LLC, a subsidiary of MidAmerican, each will acquire a 50 percent equity ownership in ETT. AEP and MidAmerican plan for ETT to invest in additional transmission projects in ERCOT. The joint venture partners anticipate investments in excess of $1 billion of joint investment in Texas ERCOT Transmission projects could be constructed by ETT during the next several years. The joint venture is anticipated to be formed and begin operations in the second half of 2007, subject to regulatory approval from the PUCT and the FERC.

In February 2007, ETT filed an informational proposal with the PUCT that addresses the Competitive Renewable Energy Zone initiative of the Texas Legislature and in April ETT filed detailed testimony and exhibits supporting this proposal. The proposal outlines opportunities for additional significant investment in transmission assets in Texas.

We believe Texas can provide a high degree of regulatory certainty for transmission investment due to the predetermination of ERCOT’s need based on reliability requirements and significant Texas economic growth as well as public policy that supports “green generation” initiatives, which require substantial transmission access. In addition, a streamlined annual interim transmission cost of service review process is available in ERCOT, which reduces regulatory lag. The use of a joint venture structure will allow us to share the significant capital requirements for the investments, and also allow us to participate in more transmission projects than previously anticipated.

AEP Interstate Project

In January 2006, we filed a proposal with the FERC and PJM to build a new 765 kV 550-mile transmission line from West Virginia to New Jersey. The 765 kV line is designed to reduce PJM congestion costs by substantially improving west-east transfer capability by approximately 5,000 MW during peak loading conditions and reducing transmission line losses by up to 280 MW. The project would also enhance reliability of the Eastern transmission grid. The projected cost for the project, as oringally proposed to PJM, is approximately $3 billion. The project is subject to PJM and state approvals, and FERC approvals of incentive cost recovery mechanisms. The projected in-service date assumes eight years for siting and construction. Due to PJM's need to review and evaluate the project in conjunction with other proposed projects, the projected in-service date is now 2015. This assumes approval by the PJM Board in mid-2007, followed by approval by the FERC on initial rates by the end of 2007.

We were the first entity to file with the Department of Energy (DOE) seeking to have the route of a proposed transmission project designated as a National Interest Electric Transmission Corridor (NIETC). The Energy Policy Act of 2005 provides for NIETC designation for areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. In August 2006, the DOE issued the “National Interest Electric Transmission Congestion Study.” In this study, DOE indicated that the mid-Atlantic Coastal area, which the AEP Interstate Project is designed to reinforce, is one of the two most critical congestion areas in the nation. In April 2007, the DOE approved the mid-Atlantic Coastal area as a NIETC which includes the entire proposed 765 kV transmission line.

In July 2006, pursuant to our request, the FERC provided that the new line is included in PJM’s formal Regional Transmission Expansion Plan to be finalized in 2007. The conditionally approved incentives include (a) a return on equity set at the high end of the “zone of reasonableness”; (b) the timely recovery of the cost of capital during the construction period; and (c) the ability to defer and recover costs incurred during the pre-construction and pre-operating period. Since the FERC has clarified that the project qualifies for these rate incentives, we expect to propose rates that will capture the incentives in a future FERC rate filing.

In April 2007, we signed a memorandum of understanding (MOU) with Allegheny Energy Inc. to form a joint venture company to build and own certain electric transmission assets within PJM including the first half of the West Virginia - New Jersey line proposed by AEP in January 2006. Under the terms of the MOU, the joint venture company will build and own approximately 250 miles of 765kV transmission lines from AEP's Amos station to the Maryland border. The MOU does not include any provisions for the remainder of the AEP Interstate Project proposal from

Allegheny's Kemptown station to New Jersey. We expect to execute definitive agreements for the joint venture with Allegheny Energy Inc. by mid-2007 and anticipate the joint venture will begin activities in the second half of 2007.

Texas Restructuring

TCC recovered its net recoverable stranded generation costs through a securitization financing and is refunding its net other true-up items through a CTC rate rider credit under 2006 PUCT orders. TCC appealed the PUCT stranded costs true-up 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, 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 statute 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 it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it 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 cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation.

Municipal customers and other intervenors also appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007, the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. He directed that these matters should be remanded to the PUCT to determine their specific impact on TCC's future true-up revenues.

In March 2007, the District Court judge reversed his earlier preliminary decision and concluded the sale of assets method to value TCC's nuclear plant was appropriate. The District Court judge did not reconsider his preliminary ruling that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. The District Court judge also determined the PUCT improperly reduced TCC's net stranded plant costs from the sale of its generating units through the commercial unreasonableness disallowance, which could have a materially favorable effect on TCC. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding. If the District Court's carrying cost rate remand ruling is ultimately upheld on appeal and remanded to the PUCT for reconsideration, the PUCT could either confirm the existing weighted average carrying cost (WACC) rate or redetermine a new rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition. TCC, the PUCT and intervenors appealed the District Court ruling to the Court of Appeals. Management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If TCC ultimately succeeds in its appeals, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

SECA Revenue Subject to Refund

We ceased collecting through-and-out transmission service (T&O) revenues in accordance with FERC orders and implemented SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. In August 2006, the 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 was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies have reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. In the second half of 2006, the AEP East companies provided a reserve of $37 million in net refunds.

In September 2006, AEP, together with Exelon and the Dayton Power and Light Company, filed an extensive post hearing brief and reply brief 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 initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. Although management believes they have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

Virginia Restructuring

In April 2004, Virginia enacted legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides APCo with specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the restructuring law, APCo defers incremental environmental generation costs and incremental T&D reliability costs for future recovery, to the extent such costs are not being recovered when incurred, and amortizes a portion of such deferrals commensurate with recovery.

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation/supply rates. The amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation/supply will return to a form of cost-based regulation. The legislation provides for, among other things, biennial rate reviews beginning in 2009, rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investment, (b) Demand Side Management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments, significant return on equity enhancements for large investments in new generation and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, utilities will retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against the fuel factor. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. APCo expects this new form of cost-based ratemaking should improve its annual return on equity and cash flow from operations when new ratemaking begins in 2009. However, with the return of cost-based regulation, APCo's generation business will again meet the criteria for application of regulatory accounting principles under SFAS 71. Results of operations and financial condition could be adversely affected when APCo is required to re-establish certain net regulatory liabilities applicable to its generation/supply business. The timing and earnings effect from such reapplication of SFAS 71 regulatory accounting for APCo's Virginia generation/supply business are uncertain at this time.

New Generation

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 during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over no more than a twelve-month period effective July 1, 2006. Through March 31, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each recovered $9 million of those costs. CSPCo and OPCo will recover the remaining amounts through June 30, 2007. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all charges collected for pre-construction costs, associated with items that may be utilized in IGCC projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. CSPCo and OPCo believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase I cost-related recoveries.

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, WV. In January 2007, at APCo's request, the WVPSC issued an order delaying the Commission's deadline for issuing an order on the certificate to December 2007. Through March 31, 2007, APCo deferred pre-construction IGCC costs totaling $10 million. If the plant is not built and these costs are not recoverable, future results of operations and cash flows would be adversely affected.

In December 2005, SWEPCo sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, SWEPCo announced plans to construct new generation to satisfy the demands of its customers. SWEPCo will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and will build a 480 MW combined-cycle natural gas fired plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build a new 600 MW base load coal plant, of which SWEPCo's investment will be 73%, in Hempstead County, Arkansas by 2011 to meet the long-term generation needs of its customers. Preliminary cost estimates for SWEPCo's share of the new facilities are approximately $1.4 billion (this total excludes the related transmission investment and AFUDC). These new facilities are subject to regulatory approvals from SWEPCo's three state commissions. The peaking generation facility in Tontitown, Arkansas has been approved by all three state commissions and Units 3 and 4 are projected to be online in July 2007 and the remaining two units by 2008. Construction is expected to begin in 2007 on the intermediate and base load facilities upon approval from the state regulatory commissions. Expenditures related to construction of these facilities are expected to total $349 million in 2007.

In September 2005, PSO sought proposals for new peaking generation to be online in 2008, and in December 2005 PSO sought proposals for base load generation to be online in 2011. PSO received proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third party. In March 2006, PSO announced plans to add 170 MW of peaking generation to its Riverside Station plant in Jenks, Oklahoma where PSO will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Also in March 2006, PSO announced plans to add 170 MW of peaking generation to its Southwestern Station plant in Anadarko, Oklahoma where they will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Combined preliminary cost estimates for these additions are approximately $120 million. In April 2007, the OCC approved a settlement agreement regarding these new peaking units. The settlement agreement provides for recovery of a purchase fee of $35 million to be paid by PSO to Lawton Cogeneration, LLC (Lawton) and for all rights to Lawton's cogeneration facility for permits, options and engineering studies. PSO will record the purchase fee as a regulatory asset and recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover the traditional costs associated with plant in service of these new peaking units. Such costs will be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units.

In July 2006, PSO announced plans to enter a joint venture with Oklahoma Gas and Electric Company (OG&E) and Oklahoma Municipal Power Authority (OMPA) where OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. PSO will own 50% of the new unit. PSO, OG&E and OMPA signed an agreement in February 2007 with Red Rock Power Partners to begin the first phase of the project. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion, and the unit is expected to be online no later than the first half of 2012. These new facilities are subject to regulatory approval from the OCC. Construction of all of these additions is expected to begin in 2007. Expenditures related to construction of these facilities are expected to total $125 million in 2007.

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. 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. The purchase of Darby is an economically efficient way to provide peaking generation to our customers at a cost below that of building a new, comparable plant.

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. The transaction is expected to close 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 plans to sell the power to CSPCo through a FERC-approved purchase power contract.

Litigation

In the ordinary course of business, we and 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 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 that have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and our 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 2006 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 the results of operations, cash flows and financial condition of AEP and its subsidiaries.

See discussion of the "Environmental Litigation" within the "Environmental Matters" section of "Significant Factors."

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 the Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (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 carbon dioxide (CO_2) 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 2006 Annual Report.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and thereafter against nonaffiliated utilities including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at our power plants occurred over a twenty-year period. A bench trial on the liability issues was held during 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants reached different results. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. In April 2007, the Supreme Court denied the petition for review. The Federal EPA also proposed a rule that would define "emissions increases" in a way that would exclude most of the challenged activities from NSR.

On April 2, 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define "major modification" in two different CAA provisions in the same way. The Court also found that the Fourth Circuit's interpretation of "major modification" as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on certain of the merits of the NSR proceedings brought against APCo, CSPCo, I&M and OPCo in U.S. District Court for the Southern District of Ohio, the U.S. Supreme Court's issuance of a ruling in the Duke Energy cases has an impact on the timing of our NSR proceedings. First, the court in the case for which a trial on liability issues has been conducted has indicated an intent to issue a decision on liability. Second, the bench trial on remedy issues, if necessary, is likely to be scheduled to begin in the third quarter of 2007.

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 CAA proceedings. 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 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 regulated rates and 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, cash flows and possibly financial condition.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2006 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

FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. We adopted FIN 48 effective January 1, 2007. The effect of this interpretation on our financial statements was an unfavorable adjustment to retained earnings of $17 million. See "FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48"" section of Note 2 and see Note 8 - Income Taxes.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

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

Our Generation and Marketing segment holds power sale contracts to commercial and industrial customers and wholesale power trading and marketing contracts within ERCOT.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, 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 management 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 Treasurer. 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 balance sheet as of March 31, 2007 and the reasons for changes in our total MTM value included on our condensed balance sheet as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
March 31, 2007
(in millions)

Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total

Current Assets	$ 319	$ 30	$ 121	$ 470	$ 6	$ 476
Noncurrent Assets	210	21	110	341	10	351
Total Assets	529	51	231	811	16	827
Current Liabilities	(228)	(35)	(120)	(383)	(20)	(403)
Noncurrent Liabilities	(92)	(8)	(117)	(217)	(2)	(219)
Total Liabilities	(320)	(43)	(237)	(600)	(22)	(622)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 209	$ 8	$ (6)	$ 211	$ (6)	$ 205

MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2007
(in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2006	$ 236	$ 2	$ (5)	$ 233
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(23)	-	-	(23)
Fair Value of New Contracts at Inception When Entered During the Period (a)	1	3	-	4
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	-	-	-	-
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	5	3	(1)	7
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(10)	-	-	(10)
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2007	$ 209	$ 8	$ (6)	211
Net Cash Flow and Fair Value Hedge Contracts				(6)
Total MTM Risk Management Contract Net Assets at March 31, 2007				$ 205

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

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

(c) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory 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 method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- 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, 2007
(in millions)

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ 14	$ 1	$ 2	$ -	$ -	$ -	$ 17
Prices Provided by Other External Sources - OTC Broker Quotes (a)	85	50	33	14	-	-	182
Prices Based on Models and Other Valuation Methods (b)	(18)	(7)	9	17	4	5	10
Total	$ 81	$ 44	$ 44	$ 31	$ 4	$ 5	$ 209
Generation and Marketing:							
Prices Actively Quoted - Exchange Traded Contracts	$ (5)	$ (4)	$ 1	$ -	$ -	$ -	$ (8)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(3)	8	1	-	-	-	6
Prices Based on Models and Other Valuation Methods (b)	3	6	(1)	-	-	2	10
Total	$ (5)	$ 10	$ 1	$ -	$ -	$ 2	$ 8
All Other:							
Prices Actively Quoted - Exchange Traded Contracts	$ 4	$ -	$ -	$ -	$ -	$ -	$ 4
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(3)	-	-	-	-	-	(3)
Prices Based on Models and Other Valuation Methods (b)	-	(1)	(4)	(4)	2	-	(7)

Total	$ 1	$ (1)	$ (4)	$ (4)	$ 2	$ -	$ (6)
Total:							
Prices Actively Quoted - Exchange Traded Contracts	$ 13	$ (3)	$ 3	$ -	$ -	$ -	$ 13
Prices Provided by Other External Sources - OTC Broker Quotes (a)	79	58	34	14	-	-	185
Prices Based on Models and Other Valuation Methods (b)	(15)	(2)	4	13	6	7	13
Total	$ 77	$ 53	$ 41	$ 27	$ 6	$ 7	$ 211

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers (OTC), industry services, or multiple-party online platforms.

(b) Prices Based on Models and Other Valuation Methods is used in the absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

The determination of the point at which a market is no longer liquid for placing it in the modeled category in the preceding table varies by market. 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, 2007

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	19
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	19
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	33
	Physical Forwards	AEP East	45

	Physical Forwards	AEP West	33
	Physical Forwards	West Coast	33
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	33
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 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 forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. 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, 2006 to March 31, 2007. 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, 2007
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2006	$ 17	$ (23)	$ (6)
Changes in Fair Value	(15)	-	(15)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(7)	-	(7)
Ending Balance in AOCI, March 31, 2007	$ (5)	$ (23)	$ (28)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ (10)	$ (1)	$ (11)

Credit Risk

We limit credit risk in our 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 meets 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 parent/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, 2007, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 3.10%, expressed in terms of net MTM assets and net receivables. As of March 31, 2007, 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	$ 665	$ 102	$ 563	1	$ 72
Split Rating	7	2	5	2	4
Noninvestment Grade	7	-	7	2	7
No External Ratings:					
Internal Investment Grade	15	-	15	3	11
Internal Noninvestment Grade	45	33	12	2	8
Total as of March 31, 2007	$ 739	$ 137	$ 602	10	$ 102
Total as of December 31, 2006	$ 998	$ 161	$ 837	9	$ 169

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, 2009. 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, 2007

	Remainder 2007	2008	2009
Estimated Plant Output Hedged	93%	89%	90%

VaR Associated with Risk Management Contracts

Commodity Price Risk

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, 2007, 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, 2007 (in millions)				Twelve Months Ended December 31, 2006 (in millions)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$2	$6	$2	$1	$3	$10	$3	$1

The High VaR for 2006 occurred in mid-August during a period of high gas and power volatility. The following day, positions were flattened and the VaR was significantly reduced.

Interest Rate Risk

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $873 million at March 31, 2007 and $870 million at December 31, 2006. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in millions, except per-share amounts and shares outstanding)
(Unaudited)

	2007	2006
REVENUES		
Utility Operations	$ 2,886	$ 2,982
Other	283	126
TOTAL	3,169	3,108
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	886	961
Purchased Energy for Resale	246	166
Other Operation and Maintenance	938	821
Gain/Loss on Disposition of Assets, Net	(23)	(68)
Depreciation and Amortization	391	348
Taxes Other Than Income Taxes	186	191
TOTAL	2,624	2,419
OPERATING INCOME	545	689
Interest and Investment Income	23	8
Carrying Costs Income	8	30
Allowance For Equity Funds Used During Construction	8	6
Gain on Disposition of Equity Investments, Net	-	3
INTEREST AND OTHER CHARGES		
Interest Expense	186	168
Preferred Stock Dividend Requirements of Subsidiaries	1	1
TOTAL	187	169
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	397	567
Income Tax Expense	130	189
Minority Interest Expense	1	-
Equity Earnings of Unconsolidated Subsidiaries	5	-
INCOME BEFORE DISCONTINUED OPERATIONS	271	378
DISCONTINUED OPERATIONS, Net of Tax	-	3
NET INCOME	$ 271	$ 381
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	397,314,642	393,653,162
BASIC EARNINGS PER SHARE		

Income Before Discontinued Operations	$	0.68	$	0.96
Discontinued Operations, Net of Tax		-		0.01
TOTAL BASIC EARNINGS PER SHARE	$	0.68	$	0.97
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		398,552,113		395,580,106
DILUTED EARNINGS PER SHARE				
Income Before Discontinued Operations	$	0.68	$	0.95
Discontinued Operations, Net of Tax		-		0.01
TOTAL DILUTED EARNINGS PER SHARE	$	0.68	$	0.96
CASH DIVIDENDS PAID PER SHARE	$	0.39	$	0.37

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in millions)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 259	$ 301
Other Temporary Cash Investments	197	425
Accounts Receivable:		
Customers	757	676
Accrued Unbilled Revenues	304	350
Miscellaneous	59	44
Allowance for Uncollectible Accounts	(31)	(30)
Total Accounts Receivable	1,089	1,040
Fuel, Materials and Supplies	942	913
Risk Management Assets	476	680
Regulatory Asset for Under-Recovered Fuel Costs	22	38
Margin Deposits	88	120
Prepayments and Other	90	71
TOTAL	3,163	3,588
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	17,736	16,787
Transmission	7,094	7,018
Distribution	11,539	11,338
Other (including coal mining and nuclear fuel)	3,423	3,405
Construction Work in Progress	2,902	3,473
Total	42,694	42,021
Accumulated Depreciation and Amortization	(15,391)	(15,240)
TOTAL - NET	27,303	26,781
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,385	2,477
Securitized Transition Assets	2,134	2,158
Spent Nuclear Fuel and Decommissioning Trusts	1,263	1,248
Goodwill	76	76
Long-term Risk Management Assets	351	378
Employee Benefits and Pension Assets	316	327
Deferred Charges and Other	945	910
TOTAL	7,470	7,574
Assets Held for Sale	-	44
TOTAL ASSETS	$ 37,936	$ 37,987

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, 2007 and December 31, 2006
(Unaudited)

		2007		2006
CURRENT LIABILITIES		(in millions)		
Accounts Payable	$	1,263	$	1,360
Short-term Debt		175		18
Long-term Debt Due Within One Year		1,377		1,269
Risk Management Liabilities		403		541
Customer Deposits		315		339
Accrued Taxes		758		781
Accrued Interest		247		186
Other		770		962
TOTAL		5,308		5,456
NONCURRENT LIABILITIES				
Long-term Debt		12,525		12,429
Long-term Risk Management Liabilities		219		260
Deferred Income Taxes		4,581		4,690
Regulatory Liabilities and Deferred Investment Tax Credits		2,759		2,910
Asset Retirement Obligations		1,035		1,023
Employee Benefits and Pension Obligations		829		823
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2		146		148
Deferred Credits and Other		933		775
TOTAL		23,027		23,058
TOTAL LIABILITIES		28,335		28,514
Cumulative Preferred Stock Not Subject to Mandatory Redemption		61		61
Commitments and Contingencies (Note 4)				
COMMON SHAREHOLDERS' EQUITY				
Common Stock Par Value $6.50:				
2007 / 2006				
Shares Authorized: 600,000,000 / 600,000,000				
Shares Issued: 419,667,962 / 418,174,728				
(21,499,992 shares were held in treasury at March 31, 2007 and December 31, 2006)		2,728		2,718
Paid-in Capital		4,270		4,221
Retained Earnings		2,795		2,696
Accumulated Other Comprehensive Income (Loss)		(253)		(223)
TOTAL		9,540		9,412
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$	37,936	$	37,987

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, 2007 and 2006
(in millions)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 271	$ 381
Less: Discontinued Operations, Net of Tax	-	(3)
Income before Discontinued Operations	271	378
Adjustments for Noncash Items:		
Depreciation and Amortization	391	348
Deferred Income Taxes	5	7
Deferred Investment Tax Credits	(6)	(7)
Carrying Costs Income	(8)	(30)
Mark-to-Market of Risk Management Contracts	22	(9)
Amortization of Nuclear Fuel	16	14
Deferred Property Taxes	(67)	(82)
Fuel Over/Under-Recovery, Net	(62)	103
Gain on Sales of Assets and Equity Investments, Net	(23)	(71)
Change in Other Noncurrent Assets	44	45
Change in Other Noncurrent Liabilities	16	10
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(29)	214
Fuel, Materials and Supplies	(3)	(50)
Margin Deposits	33	50
Accounts Payable	(31)	(115)
Accrued Taxes	32	176
Customer Deposits	(23)	(157)
Other Current Assets	(40)	19
Other Current Liabilities	(187)	(260)
Net Cash Flows From Operating Activities	351	583
INVESTING ACTIVITIES		
Construction Expenditures	(907)	(765)
Change in Other Temporary Cash Investments, Net	(20)	27
Purchases of Investment Securities	(3,693)	(2,469)
Sales of Investment Securities	3,929	2,380
Proceeds from Sales of Assets	68	111
Other	(5)	(34)
Net Cash Flows Used For Investing Activities	(628)	(750)
FINANCING ACTIVITIES		
Issuance of Common Stock	54	5
Change in Short-term Debt, Net	157	216
Issuance of Long-term Debt	247	55
Retirement of Long-term Debt	(49)	(142)
Dividends Paid on Common Stock	(155)	(146)
Other	(19)	54

Net Cash Flows From Financing Activities		235		42
Net Decrease in Cash and Cash Equivalents		(42)		(125)
Cash and Cash Equivalents at Beginning of Period		301		401
Cash and Cash Equivalents at End of Period	$	259	$	276
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	152	$	159
Net Cash Paid for Income Taxes		66		13
Noncash Acquisitions Under Capital Leases		11		20
Construction Expenditures Included in Accounts Payable at March 31,		323		246

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, 2007 and 2006
(in millions)
(Unaudited)

	Common Stock					
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	415	$ 2,699	$ 4,131	$ 2,285	$ (27)	$ 9,088
Issuance of Common Stock		1	4			5
Common Stock Dividends				(146)		(146)
Other			2			2
TOTAL						8,949
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Cash Flow Hedges, Net of Tax of $19					35	35
Securities Available for Sale, Net of Tax of $10					19	19
NET INCOME				381		381
TOTAL COMPREHENSIVE INCOME						435
MARCH 31, 2006	415	$ 2,700	$ 4,137	$ 2,520	$ 27	$ 9,384
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

See Condensed Notes to Condensed Consolidated Financial Statements.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed consolidated financial statements and footnotes were prepared in accordance with accounting principles generally accepted in the United States of America (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 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, 2007 are not necessarily indicative of results that may be expected for the year ending December 31, 2007. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2006 consolidated financial statements and notes thereto, which are included in our Annual Report on Form 10-K for the year ended December 31, 2006 as filed with the SEC on February 28, 2007.

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

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

Components		March 31, 2007		December 31, 2006
		(in millions)		
Securities Available for Sale, Net of Tax	$	10	$	18
Cash Flow Hedges, Net of Tax		(28)		(6)
SFAS 158 Adoption, Net of Tax		(235)		(235)
Total	$	(253)	$	(223)

At March 31, 2007, we expect to reclassify approximately $11 million of net losses from cash flow hedges in AOCI to Net Income during the next twelve months at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from AOCI to Net Income can differ as a result of market fluctuations.

At March 31, 2007, thirty-nine months is the maximum length of time that our exposure to variability in future cash flows is hedged with contracts designated as cash flow hedges.

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,					
	2007			2006		
	(in millions, except per share data)					
			$/share			$/share
Earnings Applicable to Common Stock	$	271		$	381	

Average Number of Basic Shares Outstanding	397.3	$	0.68	393.7	$	0.97
Average Dilutive Effect of:						
Performance Share Units	0.6		-	1.4		(0.01)
Stock Options	0.5		-	0.3		-
Restricted Stock Units	0.1		-	0.1		-
Restricted Shares	0.1		-	0.1		-
Average Number of Diluted Shares Outstanding	398.6	$	0.68	395.6	$	0.96

The assumed conversion of our share-based compensation does not affect net earnings for purposes of calculating diluted earnings per share as of March 31, 2007.

Options to purchase 0.1 million and 0.4 million shares of common stock were outstanding at March 31, 2007 and 2006, 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

	Three Months Ended March 31,			
	2007		2006	
Related Party Transactions	(in millions)			
AEP Consolidated Purchased Energy:				
Ohio Valley Electric Corporation (43.47% Owned)	$	49	$	55
Sweeny Cogeneration Limited Partnership (50% Owned)		30		34
AEP Consolidated Other Revenues - Barging and Other Transportation Services - Ohio Valley Electric Corporation (43.47% Owned)		9		7

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

On our 2006 Condensed Consolidated Statement of Income, we reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. These reclassifications totaled $7 million for the three months ended March 31, 2006.

In our segment information, we reclassified two subsidiary companies, AEP Texas Commercial & Industrial Retail GP, LLC and AEP Texas Commercial & Industrial Retail LP, from the Utility Operations segment to the Generation and Marketing segment. Combined revenues for these companies totaled $5 million for the three months ended March 31, 2006. As a result, on our 2006 Condensed Consolidated Statement of Income, we reclassified these revenues from Utility Operations to Other.

These revisions had no impact on our previously reported results of operations, cash flows or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or 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 2007 and standards issued but not implemented that we have determined relate to our operations.

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 being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption.

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. We expect that the adoption of this standard will impact MTM valuations of certain contracts, but we are unable to quantify the effect. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. We will adopt SFAS 157 effective January 1, 2008.

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.

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. 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. If we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008.

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48"

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. We adopted FIN 48 effective January 1, 2007, with an unfavorable adjustment to retained earnings of $17 million.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by 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 business combinations, revenue recognition, liabilities and equity, derivatives disclosures, 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 our 2006 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2006 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 2007 and updates the 2006 Annual Report.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs. Pursuant to the RSPs, CSPCo and OPCo implemented these proposed increases effective with the beginning of the May 2007 billing cycle. These increases are subject to refund until the PUCO issues a final order in the matter. The hearing is scheduled to begin in late May 2007.

In March 2007, CSPCo filed an application under the 4% provision of the RSP to adjust the Power Acquisition Rider (PAR) which was authorized in 2005 by the PUCO in connection with CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio. The PAR is intended to recover the difference between CSPCo's tariffed generation service rates and the cost of power acquired to serve the former Monongahela Power load. The PAR was set for an initial 17-month period of January 2006 through May 2007. The filing would adjust the PAR for the nineteen month period of June 2007 through December 2008. The filing reflects a true up for estimated under-recoveries during the initial period, $8 million as of March 31, 2007, as well as the power acquisition costs for the upcoming nineteen-month period. If approved, CSPCo's revenues would increase by $22 million and $38 million for 2007 and 2008, respectively.

In March 2007, CSPCo and OPCo filed a settlement agreement at the PUCO resolving the Ohio Supreme Court's remand of the PUCO's RSP order. The Supreme Court indicated concern with the absence of a competitive bid process as an alternative to the generation rates set by the RSP. In response, the settling parties agreed to have CSPCo and OPCo take bids for Renewable Energy Certificates (RECs). CSPCo and OPCo will give customers the option to pay a generation rate premium that would encourage the development of renewable energy sources by reimbursing CSPCo and OPCo for the cost of the RECs and the administrative costs of the program. This settlement agreement was supported by the Office of Consumers' Counsel, the Ohio Partners for Affordable Energy, the Ohio Energy Group and the PUCO staff. In May 2007, the PUCO adopted the settlement agreement in its entirety.

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the RSPs on December 31, 2008. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, as permitted by the current Ohio restructuring legislation, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009 when the RSP period ends.

Customer Choice Deferrals

As provided in the restructuring settlement agreement approved by the PUCO in 2000, CSPCo and OPCo established 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 which changes distribution rates after December 31, 2007 for OPCo and December 31, 2008 for CSPCo. Pursuant to the RSPs, recovery of these amounts for OPCo was further deferred until the next base rate filing to change distribution rates after the end of the RSP period of December 31, 2008. Through March 31, 2007, CSPCo and OPCo incurred $50 million and $51 million, respectively, of such costs and established regulatory assets of $25 million each for such costs. CSPCo and OPCo have not recognized $5 million and $6 million, respectively, of equity carrying costs, which are recognizable when collected. Management believes that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates.

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 during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over no more than a twelve-month period effective July 1, 2006. Through March 31, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each recovered $9 million of those costs. CSPCo and OPCo will recover the remaining amounts through June 30, 2007. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all charges collected for pre-construction costs, associated with items that may be utilized in IGCC projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. Management believes that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase I cost-related recoveries.

Distribution Reliability Plan

In January 2006, CSPCo and OPCo initiated a proceeding at the PUCO seeking a new distribution rate rider to fund enhanced distribution reliability programs. In the fourth quarter of 2006, as directed by the PUCO, CSPCo and OPCo filed a proposed enhanced reliability plan. The plan contemplated CSPCo and OPCo recovering approximately $28 million and $43 million, respectively, in additional distribution revenue during an eighteen month period beginning July 2007. In January 2007, the OCC filed testimony, which argued that CSPCo and OPCo should be required to improve distribution service reliability with funds from their existing rates.

In April 2007, CSPCo and OPCo filed a joint motion with the PUCO staff, the Ohio Consumers' Counsel, the Appalachian People's Action Coalition, the Ohio Partners for Affordable Energy and the Ohio Manufacturers Association to withdraw the proposed enhanced reliability plan.

Ormet

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, under a PUCO encouraged settlement agreement. The settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH to be paid by Ormet for power and a PUCO approved market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is not sufficient, an increase in RSP generation rates under the additional 4% provision of the RSPs. The $43 per MWH price to be paid by Ormet for generation services is above the industrial RSP generation tariff but below current market prices. In December 2006, CSPCo and OPCo submitted a market price of $47.69 per MWH for 2007, which is pending PUCO approval. If the PUCO approves a lower market price, it could have an adverse effect on 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 margins, which could have an adverse effect on future results of operations and cash flows.

Texas Rate Matters

TCC TEXAS RESTRUCTURING

Texas District Court Appeal Proceedings

TCC recovered its net recoverable stranded generation costs through a securitization financing and is refunding its net other true-up items through a CTC rate rider credit under 2006 PUCT orders. TCC appealed the PUCT stranded costs true-up 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, 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 statute 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 it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it 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 cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See "TCC and TNC Deferred Fuel" and"TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections below.

Municipal customers and other intervenors also appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007, the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. The judge directed that these matters should be remanded to the PUCT to determine the specific impact on TCC's future true-up revenues.

In March 2007, the District Court judge reversed his earlier preliminary decision and concluded the sale of assets method to value TCC's nuclear plant was appropriate. The District Court judge did not reconsider his preliminary ruling that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. The District Court judge also determined the PUCT improperly reduced TCC's net stranded plant costs from the sale of its generating units through the commercial unreasonableness disallowance, which could have a materially favorable effect on TCC. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding. If the District Court's carrying cost rate remand ruling is ultimately upheld on appeal and remanded to the PUCT for reconsideration, the PUCT could either confirm the existing weighted average carrying cost (WACC) rate or redetermine a new rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition. TCC, the PUCT and intervenors appealed the District Court ruling to the Court of Appeals. Management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If TCC ultimately succeeds in its appeals, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

OTHER TEXAS RESTRUCTURING MATTERS

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's 2006 true-up and securitization orders, the PUCT reduced net regulatory assets and the amount to be securitized by $51 million related to the present value of ADITC and by $10 million related to EDFIT associated with TCC's generation assets for a total reduction of $61 million.

TCC filed a request for a private letter ruling with the IRS in June 2005 regarding the permissibility under the IRS rules and regulations of the ADITC and EDFIT reduction proposed by the PUCT. The IRS issued its private letter ruling in May 2006, which stated that the PUCT's flow-through to customers of the present value of the ADITC and EDFIT benefits would result in a normalization violation. To address the matter and avoid a normalization violation, the PUCT agreed to allow TCC to defer an amount of the CTC refund totaling $103 million ($61 million in present value of ADITC and EDFIT associated with TCC's generation assets plus $42 million of related carrying costs) pending resolution of the normalization issue. If it is ultimately determined that a refund to customers through the true-up process of the ADITC and EDFIT, discussed above, is not a normalization violation, then TCC will be required to refund the $103 million, plus additional carrying costs. However, if such refund of ADITC and EDFIT is ultimately determined to cause a normalization violation, TCC anticipates it will be permitted to retain the $61 million present value of ADITC and EDFIT plus carrying costs, favorably impacting future results of operations.

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $104 million as of March 31, 2007, 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 returned to ratepayers under a nonappealable order. Management intends to continue its efforts to avoid a normalization violation that would adversely affect future results of operations and cash flows.

TCC and TNC Deferred Fuel

The TCC deferred fuel over-recovery regulatory liability is a component of the other true-up items net regulatory liability refunded through the CTC rate rider credit. In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and establish their final deferred fuel balances. In its final fuel reconciliation orders, the PUCT ordered a reduction in TCC's and TNC's recoverable fuel costs for, among other things, the reallocation of additional AEP System off-system sales margins under a FERC-approved SIA. Both TCC and TNC appealed the PUCT's rulings regarding a number of issues in the fuel orders in state court and challenged the jurisdiction of the PUCT over the allocation of off-system sales margin allocations in the federal court. Intervenors also appealed the PUCT's rulings in state court.

In 2006, the Federal District Court issued orders precluding the PUCT from enforcing the off-system sales reallocation portion of its ruling in the final TNC and TCC fuel reconciliation proceedings. The Federal court ruled, in both cases, that the FERC, not the PUCT, has jurisdiction over the allocation. The PUCT appealed both Federal District Court decisions to the United States Court of Appeals. In TNC's case, the Court of Appeals affirmed the District Court's decision. The PUCT has indicated they will appeal this ruling to the United States Supreme Court. TCC has filed a Motion for Summary Affirmance based on the outcome of the TNC appeal. For TCC, the PUCT has conceded the issue concerning the allocation of off-system sales margins to AEP West companies under the SIA as governed by the TNC case. However, the PUCT continues to challenge the allocation of those margins among AEP West companies under the CSW Operating Agreement. If the PUCT's appeals are ultimately unsuccessful, TCC and TNC could record income of $16 million and $8 million, respectively, related to the reversal of the previously recorded fuel over-recovery regulatory liabilities.

If the PUCT is unsuccessful in the federal court system, it or another interested party may file a complaint at the FERC to address the allocation issue. If a complaint at the FERC results in the PUCT's decisions being adopted by the FERC, there could be an adverse effect on results of operations and cash flows. An unfavorable FERC ruling may result in a retroactive reallocation of off-system sales margins from AEP East companies to AEP West companies under the then existing SIA allocation method. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts reallocated to the West companies from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits. Although management cannot predict the ultimate outcome of this federal litigation, management believes that its allocations were in accordance with the then existing FERC-approved SIA and that it should not have to allocate additional off-system sales margins to the West companies including TCC and TNC.

In January 2007, TCC began refunding as part of the CTC rate rider credit described above, $149 million of its $165 million over-recovered deferred fuel regulatory liability. The remaining $16 million refund related to the favorable Federal District Court order has been deferred pending the outcome of the federal court appeal and would be subject to refund only upon a successful appeal by the PUCT.

Excess Earnings

In 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. TCC refunded $55 million of excess earnings, including interest, of which $30 million went to the affiliated REP. In November 2005, the PUCT filed a petition for review with the Supreme Court of Texas seeking reversal of the Texas Court of Appeals' decision. The Supreme Court of Texas requested briefing, which has been provided, but it has not decided whether it will hear the case. If the Court of Appeals decision is upheld and the refund mechanism is found to be unlawful, the impact on TCC would then depend on: (a) how and if TCC is ordered by the PUCT to refund the excess earnings through the true-up process to ultimate customers and (b) whether TCC will be able to recover the amounts previously refunded to the REPs including the REP TCC sold to Centrica. Management is unable to predict the ultimate outcome of this litigation and its effect on future results of operations and cash flows.

OTHER TEXAS RATE MATTERS

TCC and TNC Energy Delivery Base Rate Filings

TCC and TNC each filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rates in Texas. TCC and TNC requested $81 million and $25 million in annual increases, respectively. Both requests include a return on common equity of 11.25% and the impact of the expiration of the CSW merger savings rate credits. In March 2007, various intervenors and the PUCT staff filed their recommendations. Though the recommendations varied, the range of recommended increase was $8 million to $30 million for TCC and $1 million to $14 million for TNC. The recommended return on common equity ranged from 9.00% to 9.75%. In April 2007, TCC and TNC filed rebuttal testimony reducing the requested annual increases to $70 million for TCC and $22 million for TNC including a reduced requested return on common equity of 10.75%. Hearings began in April 2007 and are scheduled to conclude in May 2007. Management expects the new base wires rates to become effective, subject to refund, in the second quarter of 2007 with a decision from the PUCT expected in the third quarter of 2007. Management is unable to predict the ultimate effect of this filing on future results of operations, cash flows and financial condition.

SWEPCo Fuel Reconciliation - Texas

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations. SWEPCo sought, in the proceedings, to include under-recoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo’s reconcilable fuel costs be reduced. The intervenor recommendations ranged from a $10 million to $28 million reduction. In February 2007, the PUCT staff filed testimony recommending that SWEPCo’s reconcilable fuel costs be reduced by $10 million. SWEPCo does not agree with the intervenor’s or staff’s recommendations and filed rebuttal testimony in February 2007. Hearings have been held and briefs have been filed. Results of operations could be adversely affected by $28 million plus carrying costs if the PUCT adopts all of the intervenor and staff recommendations. Management is unable to predict the outcome of this proceeding or its effect on future results of operations and cash flows.

Virginia Rate Matters

Virginia Restructuring

In April 2004, Virginia enacted legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides APCo with specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the restructuring law, APCo defers incremental environmental generation costs and incremental transmission and distribution reliability costs for future recovery, to the extent such costs are not being recovered when incurred, and amortizes a portion of such deferrals commensurate with recovery.

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities’ generation/supply rates. The amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation/supply will return to a form of cost-based regulation. The legislation provides for, among other things, biennial rate reviews beginning in 2009, rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investment, (b) Demand Side Management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments, significant return on equity enhancements for large investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, the amendments allow utilities to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. APCo expects this new form of cost-based ratemaking should improve its annual return on equity and cash flow from operations when new ratemaking begins in 2009. However, with the return of cost-based regulation, APCo's generation business will again meet the criteria for application of regulatory accounting principles under SFAS 71. Results of operations and financial condition could be adversely affected when APCo is required to re-establish certain net regulatory liabilities applicable to its generation/supply business. The timing and earnings effect from such reapplication of SFAS 71 regulatory accounting for APCo's Virginia generation/supply business are uncertain at this time.

APCo Virginia Base Rate Case

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including the cost of its investment in environmental equipment and a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to the fuel factor where they can be trued-up to actual. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which is estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. The major components of the $225 million base rate request include $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million mainly due to projected net environmental plant additions through September 30, 2007 and $48 million for return on equity.

In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund. The $198 million base rate increase being collected, subject to refund, includes recovery of incremental environmental compliance and transmission and distribution system reliability (E&R) costs projected to be incurred during the rate year beginning October 2006. These incremental E&R costs can be deferred and recovered through the E&R surcharge mechanism if not recovered through this base rate request. In October 2006, the Virginia SCC staff filed its direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. APCo filed rebuttal testimony in November 2006. Hearings were held in December 2006.

In March 2007, the Hearing Examiner (HE) issued a report recommending a $76 million increase in APCo's base rates and $45 million credit to the fuel factor for off-system sales margins. The HE's recommendations include a return on equity of 10.1% which would reduce APCo's revenue requirement by approximately $23 million. The HE also recommended limiting forward looking ratemaking adjustments to June 30, 2006 as opposed to September 30, 2007, which would reduce APCo's revenue requirement by approximately $72 million, of which approximately $60 million relates to incremental E&R costs that can be deferred for future recovery through the E&R surcharge mechanism. The HE further proposed to share the off-system sales margins using the twelve months ended June 30, 2006 of $101 million with 50% reducing base rates, 45% reducing fuel rates and 5% retained by APCo to determine the revenue requirement. APCo's proposal did not reduce base rates for off-system sales margins, but reduced fuel rates approximately $27 million for off-system sales margins. APCo expects a final order to be issued during 2007.

APCo is providing for a possible refund of revenues collected subject to refund consistent with the HE recommendations. Management is unable to predict the ultimate effect of this filing on future results of operations, cash flows and financial condition.

West Virginia Rate Matters

APCo and WPCo ENEC Filing

In April 2007, the WVPSC issued an order establishing an investigation and hearing of APCo's and WPCo's 2007 Expanded Net Energy Cost (ENEC) compliance filing. 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 and other energy/transmission items. In the March 2007 ENEC joint filing, APCo and WPCo filed for an increase of approximately $101 million including a $72 million increase in ENEC and a $29 million increase in construction surcharges to become effective July 1, 2007. A hearing on the compliance filing is scheduled for May 2007.

APCo IGCC

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, WV. In January 2007, at APCo's request, the WVPSC issued an order delaying the Commission's deadline for issuing an order on the certificate to December 2007. Through March 31, 2007, APCo deferred pre-construction IGCC costs totaling $10 million. If the plant is not built and these costs are not recoverable, future results of operations and cash flows would be adversely affected.

Indiana Rate Matters

I&M Depreciation Study Filing

In February 2007, I&M filed a request with the IURC for approval of revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counsel that would provide direct benefits to I&M's customers if new depreciation rates are approved by the IURC. The direct benefits would include a $5 million credit to fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement is approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense on an Indiana jurisdictional basis of approximately $69 million reflecting an NRC-approved 20-year extension of the Cook Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition was not a request for a change in customers' electric service rates. As proposed, the book depreciation reduction would increase earnings but would not impact cash flows until rates are revised. The IURC held a public hearing in April 2007. I&M requested expeditious review and approval of its filing, but management cannot predict the outcome of the request or the timing of any approved depreciation reduction. If approved as filed, pretax earnings would increase by $64 million in 2007.

Kentucky Rate Matters

KPCo Environmental Surcharge Filing

In July 2006, KPCo filed for approval of an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge. KPCo estimates the amended environmental compliance plan and revised tariff would increase revenues over 2006 levels by approximately $2 million in 2007 and $6 million in 2008 for a total of $8 million of additional revenue at current cost projections. In January 2007, the KPSC issued an order approving KPCo's proposed plan and surcharge. Future recovery is based upon actual environmental costs and is subject to periodic review and approval of those actual costs by the KPSC.

In November 2006, the Kentucky Attorney General and the Kentucky Industrial Utility Consumers (KIUC) filed an appeal with the Kentucky Court of Appeals of the Franklin Circuit Court's 2006 order upholding the KPSC's 2005

Environmental Surcharge order. In its order, the KPSC approved KPCo's recovery of its environmental costs at its Big Sandy Plant and its share of environmental costs incurred as a result of the AEP Power Pool capacity settlement. The KPSC has allowed KPCo to recover these FERC-approved allocated costs, via the environmental surcharge, since the KPSC's first environmental surcharge order in 1997. KPCo presently recovers $7 million a year in environmental surcharge revenues.

In March 2007, the KPSC issued an order, at the request of the Kentucky Attorney General, stating the environmental surcharge collections authorized in the January 2007 order that are associated with out-of-state generating facilities should be collected over the six months beginning March 2007, subject to refund, pending the outcome of the court of appeals process. At this time, management is unable to predict the outcome of this proceeding and its effect on KPCo's current environmental surcharge revenues or on the January 2007 KPSC order increasing KPCo's environmental rates.

Oklahoma Rate Matters

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

In 2002, PSO under-recovered $44 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with the proposed reallocation of off-system sales margins of $27 million to $37 million and with $9 million attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the $9 million of reallocated purchased power costs assigned to wholesale customers had been refunded, thus removing that issue from its recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. The United States District Court for the Western District of Texas issued orders in September 2005 regarding a TNC fuel proceeding and in August 2006 regarding a TCC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has sole jurisdiction over that allocation. The PUCT appealed the ruling. The United States Court of Appeals for the Fifth Circuit, issued a decision in December 2006 regarding the TNC fuel proceeding that affirmed the United States District Court ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals other than the staff's original recommendation that PSO be allowed to recover the $42 million over three years and will defend its right to recover its under-recovered fuel balance. Management believes that if the position taken by the federal courts in the Texas proceeding is applied to PSO's case, then the OCC should be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party could file a complaint at the FERC alleging the allocation of off-system sales margins to PSO is improper, which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. However, to date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies, but even if one were asserted, management believes that it would not prevail.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. The OCC staff filed testimony finding no disallowances in the test year data. The Attorney General of Oklahoma filed testimony stating that they could not determine if PSO's gas procurement activities were prudent, but did not include a recommended disallowance. However, an intervenor filed testimony in June 2006 proposing the disallowance of $22 million in fuel costs based on a historical review of potential hedging opportunities that he alleges existed during the year. A hearing was held in August 2006 and management expects a recommendation from the ALJ in 2007.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to the required biennial reviews. In compliance with an OCC order, PSO is required to file its testimony by June 15, 2007. This proceeding will cover the year 2005.

Management cannot predict the outcome of the pending fuel and purchased power reviews or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the unrecovered 2002 reallocation of such costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

PSO Rate Filing

In November 2006, PSO filed a request to increase base rates $50 million for Oklahoma jurisdictional customers with a proposed effective date in the second quarter of 2007. PSO sought a return on equity of 11.75%. PSO also proposed a formula rate plan that, if approved as filed, will permit PSO to defer any unrecovered costs as a result of a revenue deficiency that exceeds 50 basis points of the allowed return on equity for recovery within twelve months beginning six months after the test year. The formula would enable PSO to recover on a timely basis the cost of its new generation, transmission and distribution construction (including carrying costs during construction), provide the opportunity to achieve the approved return on equity and avoid recording a significant AFUDC that would have been recorded during the construction time period.

In March 2007, the OCC staff and various intervenors filed testimony. The recommendations were base rate reductions that ranged from $18 million to $52 million. The recommended returns on equity ranged from 9.25% to 10.09%. These recommendations included reductions in depreciation expense of approximately $25 million, which has no earnings impact. The OCC staff filed testimony supporting a formula rate plan, generally similar to the one proposed by PSO. In April 2007, PSO filed rebuttal testimony regarding various issues raised by the OCC Staff and the intervenors. As a result of rebuttal testimony, PSO reduced its base rate request by $2 million. Hearings commenced on May 1, 2007.

Management is unable to predict the outcome of these proceedings, however, if rates are not increased in an amount sufficient to recover expected unavoidable cost increases future results of operations, cash flows and possibly financial condition could be adversely affected.

PSO Lawton and Peaking Generation Settlement Agreement

On November 26, 2003, pursuant to an application by Lawton Cogeneration, L.L.C. (Lawton) seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court (the Court). In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Court issued a decision on June 21, 2005, affirming portions of the OCC's order and remanding certain provisions. The Court affirmed the OCC's finding that Lawton established a legally enforceable obligation and ruled that it was within the OCC's discretion to award a 20-year contract and to base the capacity payment on a peaking unit. The Court directed the OCC to revisit its determination of PSO's avoided energy cost. Hearings were held on the remanded issues in April and May 2006.

In April 2007, all parties in the case filed a settlement agreement with the OCC resolving all issues. The OCC approved the settlement agreement in April 2007. The settlement agreement provides for a purchase fee of $35 million to be paid by PSO to Lawton and for Lawton to provide, at PSO's direction, all rights to the Lawton Cogeneration Facility for permits, options and engineering studies. PSO will record the purchase fee as a regulatory asset and recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service of its new peaking units to be located at the Southwestern Station and Riverside Station at the time these units are placed in service. PSO may request approval from the OCC for recovery of costs exceeding the cost cap if special circumstances occurred necessitating a higher level of costs. Such costs will continue to be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units. Once the cost recovery for the new peaking units begins in mid-2008, PSO expects annual revenues of an estimated $36 million related to cost recovery of the peaking units and the purchase fee. This settlement agreement was supported by the OCC Staff, the Attorney General, the Oklahoma Industrial Energy Consumers and Lawton Cogeneration, L.L.C.

Louisiana Rate Matters

SWEPCo Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. Due to multiple delays, in April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed updated financial review schedules in May 2006 showing a return on equity of 9.44% compared to the previously authorized return on equity of 11.1%.

In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdiction customers, based on a proposed 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain ongoing operations and maintenance expense levels. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo filed rebuttal testimony in January 2007. A decision is not expected until mid or late 2007. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely impact future results of operations, cash flows and possibly financial condition.

FERC Rate Matters

Transmission Rate Proceedings at the FERC

The FERC PJM Regional Transmission Rate Proceeding

At AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP and other transmission owners for the regional transmission facilities they provide to PJM, which provides service for the benefit of customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC. This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway.

Parties to the regional rate proceeding proposed the following rate regimes:

- AEP/AP proposed a Highway/Byway rate design in which:
  - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a “Highway” rate that all load serving entities (LSEs) would pay based on peak demand. The AEP/AP proposal would produce about $125 million in additional revenues per year for AEP from users in other zones of PJM.
  - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM’s existing rate design.
- Two other utilities, Baltimore Gas & Electric Company (BG&E) and Old Dominion Electric Cooperative (ODEC), proposed a Highway/Byway rate that includes transmission facilities above 200 kV, which would produce lower revenues for AEP than the AEP/AP proposal.
- In another competing Highway/Byway proposal, a group of LSEs proposed rates that would include existing 500 kV and higher voltage facilities and new facilities above 200 kV in the Highway rate, which would produce considerably lower revenues for AEP than the AEP/AP proposal.
- In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or “Postage Stamp” type of rate design that would include all transmission facilities, which would produce higher transmission revenues for AEP than the AEP/AP proposal.

All of these proposals were challenged by a majority of other transmission owners in the PJM region, who favor continuation of the existing PJM rate design which provides AEP with no compensation for through and out traffic on its east zone transmission system. Hearings were held in April 2006 and the ALJ issued an initial decision in July 2006. The ALJ found the existing PJM zonal rate design to be unjust and determined that it should be replaced. The ALJ found that the Highway/Byway rates proposed by AEP/AP and BG&E/ODEC and the Postage Stamp rate proposed by the FERC staff to be just and reasonable alternatives. The ALJ also found FERC staff’s proposed Postage Stamp rate to be just and reasonable and recommended that it be adopted. The ALJ also found that the effective date of the rate change should be April 1, 2006 to coincide with SECA rate elimination. Because the Postage Stamp rate was found to produce greater cost shifts than other proposals, the judge also recommended that the design be phased-in. Without a phase-in, the Postage Stamp method would produce more revenue for AEP than the AEP/AP proposal. The phase-in of Postage Stamp rates would delay the full impact of that result until about 2012.

AEP filed briefs noting exceptions to the initial decision and replies to the exceptions of other parties. AEP argued that a phase-in should not be required. Nevertheless, AEP argued that if the FERC adopts the Postage Stamp rate and a phase-in plan, the revenue collections curtailed by the phase-in should be deferred and paid later with interest.

During 2006, the AEP East companies sought to increase retail rates in most of their states to recover lost T&O and SECA revenues. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of its share of the transmission revenue reduction in new rates effective March 30, 2006.
- In Ohio, CSPCo and OPCo recover their FERC-approved OATT that reflects their share of the full transmission revenue requirement retroactive to April 1, 2006 under a May 2006 PUCO order.
- In West Virginia, APCo settled a rate case, which provided for the recovery of its share of the T&O/SECA transmission revenue reduction beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of its share of the T&O/SECA transmission revenue reduction starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.
- In Michigan, I&M has not filed to seek recovery of the lost transmission revenues.

In April 2007, the FERC issued an order reversing the ALJ decision. The FERC ruled that the current PJM rate design is just and reasonable. The FERC further ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants. As a result of this order, the AEP East companies retail customers will be asked to bear the full cost of the existing AEP east transmission zone facilities. However, the AEP East companies customers will also be charged a share of the cost of new 500 kV and higher voltage transmission facilities built in PJM, of which the vast majority for the foreseeable future will not be needed by their customers, but will bolster service and reduce costs in other zones of PJM. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them as a result of this order, if upheld. AEP will request rehearing of this order. Management cannot estimate at this time what effect, if any, this order will have on their future construction of new east transmission facilities, results of operations, cash flows and financial condition.

The AEP East companies presently recover from retail customers approximately 85% of the reduction in transmission revenues of $128 million a year. Future results of operations, cash flows and financial condition will continue to be adversely affected in Indiana and Michigan until these lost transmission revenues are recovered in retail rates.

SECA Revenue Subject to Refund

The AEP East companies ceased collecting through-and-out transmission service (T&O) revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the 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 or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than 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 as follows:

	Gross SECA Revenues Recognized (in millions)
Year Ended December 31, 2006 (a)	$ 43
Year Ended December 31, 2005	163
Year Ended December 31, 2004	14

(a) Represents revenues through March 31, 2006, when SECA rates expired, and excludes all provisions for refund.

Approximately $19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

In August 2006, the 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 was not 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.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. In the second half of 2006, the AEP East companies provided reserves of $37 million in net refunds.

In September 2006, AEP, together with Exelon and DP&L, filed an extensive post-hearing brief and reply brief 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 initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. Although management believes they have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2006 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 company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At March 31, 2007, the maximum future payments for all the LOCs are approximately $27 million with maturities ranging from June 2007 to March 2008.

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 $85 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 46. 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, 2007, SWEPCo has collected approximately $30 million through a rider for final mine closure costs, of which approximately $13 million is recorded in Deferred Credits and Other and approximately $17 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 2006 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 $2.2 billion (approximately $1 billion relates to the BOA litigation, see "Enron Bankruptcy" section of this note). There are no material liabilities recorded for any indemnifications.

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. At March 31, 2007, the maximum potential loss for these lease agreements was approximately $56 million ($36 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, we 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. At March 31, 2007, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. 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 allege that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred at our generating units over a twenty-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke

Energy case.

Under the CAA, if a plant undertakes a major modification that results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to routine maintenance, replacement of degraded equipment or failed component or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

Cases are pending that could affect CSPCo’s share of jointly-owned units at Beckjord, Zimmer, and Stuart Stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as “routine replacements.” In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA’s request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. In April 2007, the Supreme Court denied the petition for review. The Federal EPA also proposed a rule that would define “emissions increases” in a way that most of the challenged activities would be excluded from NSR.

On April 2, 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals’ decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define “major modification” in two different CAA provisions in the same way. The Court also found that the Fourth Circuit’s interpretation of “major modification” as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on certain of the merits of the NSR proceedings brought against APCo, CSPCo, I&M and OPCo in U.S. District Court for the Southern District of Ohio, the U.S. Supreme Court’s issuance of a ruling in the Duke Energy cases has an impact on the timing of our NSR proceedings. First, the court in the case for which a trial on liability issues has been conducted has indicated an intent to issue a decision on liability. Second, the bench trial on remedy issues, if necessary, is likely to be scheduled to begin in the third quarter of 2007.

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 CAA proceedings. 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 regulated rates and 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. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled for the second quarter of 2007.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation limiting the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. 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 removing the heat input references from the Welsh permit and clarifying the sulfur content of fuels burned at the plant is limited to 0.5% on an as-received basis. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration.

We are unable to predict the timing of any future action by TCEQ 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 defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. On April 2, 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. We believe the actions are without merit and intend to defend against the claims.

TEM Litigation

OPCo 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 dated November 15, 2000 (PPA). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

In September 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 we 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 AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In August 2005, a federal judge ruled that TEM had breached the contract and awarded us damages of $123 million plus prejudgment interest. Any eventual proceeds will be recorded as a gain when received.

In September 2005, TEM posted a $142 million letter of credit as security pending appeal of the judgment. Both parties filed Notices of Appeal with the United States Court of Appeals for the Second Circuit, which heard oral argument on the appeals in December 2006. We cannot predict the ultimate outcome of this proceeding.

Enron Bankruptcy

In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 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, Bank of America (BOA) and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of 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. In 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage facility. In 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In August 2006, the Court of Appeals for the First District of Texas vacated the trial court’s judgment and dismissed the BOA Syndicate’s case. The BOA Syndicate did not seek review of this decision. In June 2004, BOA filed an amended petition in a separate lawsuit 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. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL’s motion to have the case assigned to the judge who heard the case originally was granted. HPL intends to defend against any renewed claims by BOA.

In 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage facility to HPL. 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 Bammel storage facility lease arrangement with Enron and 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 including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA’s Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel facility and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge’s decision. In April 2005, the Judge entered an order overruling BOA’s objections, denying BOA’s Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. The case in federal court in Texas was set for trial beginning April 2007 but the Court continued the trial pending a decision on the motions for summary judgment in the New York case.

In February 2007, the Judge in the New York action, after hearing oral argument on the motions for summary judgment, made a series of oral “informal findings” and submitted a written memorandum to the parties’ counsel. In the memorandum to counsel, the Judge stated that he was denying several of AEP’s motions for partial summary judgment and granting several of BOA motions for summary judgment. The substantive matters left open for further proceedings include the issue of the nature of the gas subject to BOA security interest and the value of that interest. The Judge stated that the memorandum to counsel is not an opinion or an order, and that no opinion or order will be issued until all motions pending before the Court have been decided. The Judge heard additional arguments on the summary judgment motions in March 2007. At this time we are unable to predict how the Judge will rule on the pending motions due to the complexity of those issues and the parties' disagreement over each issue. If the Judge issues a judgment directing AEP to pay an amount in excess of the gain on the sale of HPL described below and if AEP is unsuccessful in having the judgment reversed or modified, the judgment could have a material adverse effect on the results of operations, cash flow, and possibly financial condition.

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 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 determination of the gain on sale, estimated to be $380 million at March 31, 2007 and December 31, 2006, and the recognition of the gain are dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter. The deferred gain is included in Deferred Credits and Other on our Condensed Consolidated Balance Sheets.

Although management is unable to predict the outcome of the remaining lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows and financial condition.

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 2006, the plaintiffs filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit. Briefing of this appeal was completed in December 2006 and the parties await the scheduling of oral argument. 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 forty energy companies, including AEP, and two publishing companies 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 filed in California. In addition, a number of other cases were filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases were transferred to the United States District Court for the District of Nevada but subsequently were remanded to California state court. In 2005, the judge in Nevada dismissed three of the remaining cases (AEP was a defendant in one of these cases), on the basis of the filed rate doctrine. Plaintiffs in these cases appealed the decisions. 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. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the Nevada utilities. In 2001, the Nevada utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered as the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 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. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

5. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

ACQUISITIONS

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 approximately $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 approximately $325 million and the assumption of liabilities of approximately $2 million. AEGCo will complete 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.

2006

None

DISPOSITIONS

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 $42.8 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)

During March 2007, we sold 130,000 shares of ICE and recognized a $16 million pretax gain ($10 million, net of tax). We recorded the gains in Interest and Investment Income on our 2007 Condensed Consolidated Statement of Income. We recorded our remaining investment of approximately 138,000 shares in Other Temporary Cash 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. We received $20 million and $70 million payments in 2007 and 2006, respectively, for our share in earnings. These payments are reflected in Gain/Loss on Disposition of Assets, Net on our Condensed Consolidated Statements of Income. The payment we received in 2007 was the final payment under the earnings sharing agreement.

2006

Compresion Bajio S de R.L. de C.V. (All Other)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600 MW power plant in Mexico. We completed the sale in February 2006 for approximately $29 million with no effect on our 2006 results of operations.

DISCONTINUED OPERATIONS

We determined that certain of our operations were discontinued operations and classified them as such for all periods presented. We recorded no income or charges related to our discontinued operations during the first quarter of 2007. During the first quarter of 2006, we had discontinued operations from U.K. Generation related to a release of accrued liabilities for the London office lease and tax adjustments from the sale. We recorded pretax income related to U.K. Generation of $5 million ($3 million, net of tax) during the first quarter of 2006.

ASSETS HELD FOR SALE

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. The sale did not have a significant effect on our results of operations nor do we expect any remaining litigation to have a significant effect on our results of operations.

We classified TCC's assets related to the Oklaunion Power Station in Assets Held for Sale on our Condensed Consolidated Balance Sheet at December 31, 2006. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by our Registrant Subsidiaries except TNC.

Our Assets Held for Sale were as follows:

Texas Plants	March 31, 2007	December 31, 2006
	(in millions)	
Other Current Assets	$ -	$ 1
Property, Plant and Equipment, Net	-	43
Total Assets Held for Sale	$ -	$ 44

6. BENEFIT PLANS

We adopted SFAS 158 as of December 31, 2006. We recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes will be deferred for future recovery.

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, 2007 and 2006:

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
	(in millions)			
Service Cost	$ 24	$ 24	$ 10	$ 10
Interest Cost	59	57	26	25
Expected Return on Plan Assets	(85)	(83)	(26)	(23)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	15	20	3	5
Net Periodic Benefit Cost	$ 13	$ 18	$ 20	$ 24

7. BUSINESS SEGMENTS

As outlined in our 2006 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 all 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 and Virginia continue to have commission-determined transition rates. In April 2007, the Virginia legislature approved amendments recommended by the Governor providing for the re-regulation of electric utility generation/supply rates. See “Virginia Restructuring” section of Note 3.

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 34 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and Lower Mississippi rivers. Approximately 35% of the barging operations relates to the transportation of coal, 28% relates to agricultural products, 21% relates to steel and 16% relates to other commodities.

Generation and Marketing

- IPPs, wind farms and marketing and risk management activities primarily in ERCOT.

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

· Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
· Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in the fourth quarter of 2006.

The tables below present our reportable segment information for the three months ended March 31, 2007 and 2006 and balance sheet information as of March 31, 2007 and December 31, 2006. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's segment presentation.

		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	$ 117	$ 115	$ 51	$ -	$ 3,169
Other Operating Segments	147	3	(73)	(45)	(32)	-
Total Revenues	$ 3,033	$ 120	$ 42	$ 6	$ (32)	$ 3,169
Net Income (Loss)	$ 253	$ 15	$ (1)	$ 4	$ -	$ 271

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended March 31, 2006						
Revenues from:						
External Customers	$ 2,982	$ 116	$ 13	$ (3)	$ -	$ 3,108
Other Operating Segments	(16)	3	-	22	(9)	-
Total Revenues	$ 2,966	$ 119	$ 13	$ 19	$ (9)	$ 3,108
Income (Loss) Before Discontinued Operations	$ 365	$ 21	$ 4	$ (12)	$ -	$ 378
Discontinued Operations, Net of Tax	-	-	-	3	-	3
Net Income (Loss)	$ 365	$ 21	$ 4	$ (9)	$ -	$ 381

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
March 31, 2007			(in millions)			
Total Property, Plant and Equipment	$ 42,092	$ 239	$ 565	$ 35	$ (237)(c)	$ 42,694

Accumulated Depreciation and Amortization	15,244	53	90	7	(3)(c)	15,391
Total Property, Plant and Equipment - Net	$ 26,848	$ 186	$ 475	$ 28	$ (234)(c)	$ 27,303
Total Assets	$ 36,789	$ 305	$ 705	$ 11,732	$ (11,595)(b)	$ 37,936

December 31, 2006	Utility Operations	Nonutility Operations MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 41,420	$ 239	$ 327	$ 35	$ -	$ 42,021
Accumulated Depreciation and Amortization	15,101	51	83	5	-	15,240
Total Property, Plant and Equipment - Net	$ 26,319	$ 188	$ 244	$ 30	$ -	$ 26,781
Total Assets	$ 36,632	$ 315	$ 342	$ 11,460	$ (10,762)(b)	$ 37,987
Assets Held for Sale	44	-	-	-	-	44

(a) All Other includes:

- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in the fourth quarter of 2006.

(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) Reconciling Adjustments for Total Property, Plant and Equipment and Accumulated Depreciation and Amortization as of March 31, 2007 represent the elimination of an intercompany capital lease that began during the first quarter of 2007.

8. INCOME TAXES

We join in the filing of a consolidated federal income tax return with our subsidiaries in the American Electric Power (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 expense. The tax benefit of the parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

Audit Status

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

We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for years prior to 1997. We have effectively settled all outstanding proposed IRS adjustments for years 1997 through 1999 and through June 2000 for the CSW pre-merger tax period and anticipate payment for the agreed adjustments to occur during 2007. Returns for the years 2000 through 2003 are presently being audited by the IRS and we anticipate that the audit will be completed by the end of 2007.

The IRS has proposed certain significant adjustments to AEP's foreign tax credit and interest allocation positions. Management is currently evaluating those proposed adjustments to determine if it agrees, but if accepted, we do not anticipate that the adjustments would result in a material change to our financial position.

FIN 48 Adoption

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we recognized approximately a $17 million 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.

At January 1, 2007, the total amount of unrecognized tax benefits under FIN 48 was $175 million. We believe it is reasonably possible that there will be a $46 million net decrease in unrecognized tax benefits due to the settlement of audits and the expiration of statute of limitations within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $73 million. There are $66 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

Prior to the adoption of FIN 48, we recorded interest and penalty accruals related to income tax positions in tax accrual accounts. With the adoption of FIN 48, we began recognizing interest accruals related to income tax positions in interest income or expense as applicable, and penalties in operating expenses. As of January 1, 2007, we accrued approximately $25 million for the payment of uncertain interest and penalties.

9. FINANCING ACTIVITIES

Long-term Debt

Type of Debt		March 31, 2007		December 31, 2006
		(in millions)		
Senior Unsecured Notes	$	8,903	$	8,653
Pollution Control Bonds		1,950		1,950
First Mortgage Bonds		90		90
Defeased First Mortgage Bonds (a)		27		27
Notes Payable		320		337
Securitization Bonds		2,303		2,335
Notes Payable To Trust		113		113
Spent Nuclear Fuel Obligation (b)		251		247
Other Long-term Debt		2		2
Unamortized Discount (net)		(57)		(56)
Total Long-term Debt Outstanding		13,902		13,698
Less Portion Due Within One Year		1,377		1,269
Long-term Portion	$	12,525	$	12,429

(a) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of $19 million at both March 31, 2007 and December 31, 2006. Trust Fund Assets related to this obligation of $23 million and $2 million at March 31, 2007 and December 31, 2006, respectively, are included in Other Temporary Cash Investments and $0 and $21 million at March 31, 2007 and December 31, 2006, respectively, are included in Other Noncurrent Assets on our Condensed Consolidated Balance Sheets. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond had a balance of $8 million at both March 31, 2007 and December 31, 2006. Trust fund assets related to this obligation of $9 million at both March 31, 2007 and December 31, 2006 are included in Other Temporary Cash Investments on our Condensed Consolidated Balance Sheet. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with 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 $276 million and $274 million at March 31, 2007 and December 31, 2006, 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 2007 are shown in the tables below.

Company	**Type of Debt**	**Principal Amount (in millions)**	**Interest Rate (%)**	**Due Date**
Issuances:				
SWEPCo	Senior Unsecured Notes	$ 250	5.55	2017
Total Issuances		$ 250(a)		

The above borrowing arrangement does not contain guarantees, collateral or dividend restrictions.

(a) Amount indicated on statement of cash flows of $247 million is net of issuance costs and unamortized premium or discount.

Company	**Type of Debt**	**Principal Amount Paid (in millions)**	**Interest Rate (%)**	**Due Date**
Retirements and Principal Payments:				
OPCo	Notes Payable	$ 1	6.81	2008
OPCo	Notes Payable	6	6.27	2009
SWEPCo	Notes Payable	2	4.47	2011
SWEPCo	Notes Payable	4	6.36	2007

SWEPCo	Notes Payable	1	Variable	2008
TCC	Securitization Bonds	32	5.01	2008
Non-Registrant:				
AEP Subsidiaries	Notes Payable	3	Variable	2017
Total Retirements	$	49		

In April 2007, OPCo issued $400 million of three-year floating rate notes at an initial rate of 5.53% due in 2010. The proceeds from this issuance will contribute to our investment in environmental equipment.

Short-term Debt

Short-term debt is used to fund our corporate borrowing program and fund other short-term cash needs. Our outstanding short-term debt is as follows:

	March 31, 2007		**December 31, 2006**	
Type of Debt	**Outstanding Amount (in millions)**	**Interest Rate**	**Outstanding Amount (in millions)**	**Interest Rate**
Commercial Paper - AEP	$ 150	5.43% (a)	$ -	-
Commercial Paper - JMG (b)	5	5.56%	1	5.56%
Line of Credit - Sabine (c)	20	6.52%	17	6.38%
Total	$ 175		$ 18	

(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 is consolidated under FIN 46. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

In March 2007, we amended the terms of our credit facilities. The amended facilities are structured as two $1.5 billion credit facilities, with an option in each to issue up to $300 million as letters of credit, expiring separately in March 2011 and April 2012.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

We engage in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. We derive operating revenues from the sale of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC-approved long-term unit power agreements through December 2022. Under the terms of its unit power agreement, I&M agreed to purchase all of our Rockport energy and capacity unless it is sold to other utilities or affiliates. I&M assigned 30% of its rights to energy and capacity to KPCo.

The unit power agreements provide for a FERC-approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Under the terms of the unit power agreements, we accumulate all expenses monthly and prepare bills for our affiliates. In the month the expenses are incurred, we recognize the billing revenues and establish a receivable from the affiliated companies. The co-owners divide the costs of operating the plant.

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 2.9
Change in Gross Margin:		
Wholesale Sales		(0.7)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(1.3)	
Interest Expense	(0.5)	
Total Change in Operating Expenses and Other		(1.8)
Income Tax Expense (Credit)		1.2
First Quarter of 2007		$ 1.6

Net Income decreased $1.3 million for 2007 compared with 2006. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant calculated and adjusted monthly for over/under billings.

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, decreased $0.7 million primarily due to year-end tax adjustments reflected in January's bill.

Other Operation and Maintenance expenses increased $1.3 million primarily due to increased maintenance cost reflecting more planned and forced outages at the Rockport Plant in 2007 than 2006.

Interest Expense increased $0.5 million primarily due to increased rates on short-term borrowings and increased money pool borrowings.

Income Taxes

Income Tax Expense (Credit) decreased $1.2 million primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Significant Factors

Lawrenceburg Generating Station

In January 2007, we agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. The transaction is expected to close 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. This new generation acquisition will be financed by a capital contribution from AEP and issuance of debt related to this acquisition. We plan to sell the power to CSPCo through a FERC-approved purchase power contract.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in our 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for a discussion of adoption of new accounting pronouncements.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING REVENUES	$ 77,151	$ 78,151
EXPENSES		
Fuel Used for Electric Generation	43,649	43,961
Rent - Rockport Plant Unit 2	17,071	17,071
Other Operation	3,326	3,068
Maintenance	3,811	2,786
Depreciation and Amortization	5,990	5,975
Taxes Other Than Income Taxes	1,081	1,070
TOTAL	74,928	73,931
OPERATING INCOME	2,223	4,220
Interest Expense	(1,252)	(722)
INCOME BEFORE INCOME TAXES	971	3,498
Income Tax Expense (Credit)	(620)	570
NET INCOME	$ 1,591	$ 2,928

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
BALANCE AT BEGINNING OF PERIOD	$ 30,942	$ 26,038
FIN 48 Adoption, Net of Tax	27	-
Net Income	1,591	2,928
Cash Dividends Declared	-	1,998
BALANCE AT END OF PERIOD	$ 32,560	$ 26,968

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

		2007		2006
CURRENT ASSETS				
Accounts Receivable - Affiliated Companies	$	29,380	$	31,060
Fuel		28,414		37,701
Materials and Supplies		8,024		7,873
Accrued Tax Benefits		1,820		3,808
Prepayments and Other		38		57
TOTAL		67,676		80,499
PROPERTY, PLANT AND EQUIPMENT				
Electric - Production		688,599		686,776
Other		2,567		2,460
Construction Work in Progress		15,931		15,198
Total		707,097		704,434
Accumulated Depreciation and Amortization		405,676		398,422
TOTAL - NET		301,421		306,012
OTHER NONCURRENT ASSETS				
Regulatory Assets		5,403		5,438
Deferred Charges and Other		3,667		1,382
TOTAL		9,070		6,820
TOTAL ASSETS	$	378,167	$	393,331

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 29,997	$ 53,646
Accounts Payable:		
General	6	549
Affiliated Companies	18,918	27,935
Accrued Taxes	7,092	3,685
Accrued Rent - Rockport Plant Unit 2	23,427	4,963
Other	521	1,200
TOTAL	79,961	91,978
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	44,839	44,837
Deferred Income Taxes	19,792	19,749
Regulatory Liabilities and Deferred Investment Tax Credits	76,069	79,650
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	87,370	88,762
Deferred Credits and Other	13,142	12,979
TOTAL	241,212	245,977
TOTAL LIABILITIES	321,173	337,955
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - Par Value - $1,000 Per Share:		
Authorized - 1,000 Shares		
Outstanding - 1,000 Shares	1,000	1,000
Paid-in Capital	23,434	23,434
Retained Earnings	32,560	30,942
TOTAL	56,994	55,376
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 378,167	$ 393,331

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 1,591	$ 2,928
Adjustments for Noncash Items:		
Depreciation and Amortization	5,990	5,975
Deferred Income Taxes	(1,205)	(1,126)
Deferred Investment Tax Credits	(820)	(827)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(1,392)	(1,392)
Deferred Property Taxes	(2,516)	(2,734)
Changes in Other Noncurrent Assets	47	(403)
Changes in Other Noncurrent Liabilities	200	374
Changes in Certain Components of Working Capital:		
Accounts Receivable	1,680	1,607
Fuel, Materials and Supplies	9,136	(1,044)
Accounts Payable	(9,560)	(2,068)
Accrued Taxes, Net	5,252	6,179
Accrued Rent - Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(28)	(35)
Other Current Liabilities	(332)	(379)
Net Cash Flows From Operating Activities	26,507	25,519
INVESTING ACTIVITIES		
Construction Expenditures	(2,841)	(1,693)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(23,649)	(21,814)
Principal Payments for Capital Lease Obligations	(17)	(14)
Dividends Paid on Common Stock	-	(1,998)
Net Cash Flows Used For Financing Activities	(23,666)	(23,826)
Net Change in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 1,398	$ 1,109
Net Cash Received for Income Taxes	(439)	-
Noncash Acquisitions Under Capital Leases	1	27

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to AEGCo'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 AEGCo.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 4
Changes in Gross Margin:		
Off-system Sales	7	
Texas Wires	6	
Transmission Revenues	1	
Other	28	
Total Change in Gross Margin		42
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	2	
Depreciation and Amortization	(13)	
Taxes Other Than Income Taxes	2	
Carrying Costs Income	(19)	
Other Income	5	
Interest Expense	(19)	
Total Change in Operating Expenses and Other		(42)
First Quarter of 2007		$ 4

Net Income remained relatively flat in the first quarter of 2007 compared to the first quarter of 2006.

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

- Margins from Off-system Sales increased $7 million primarily due to lower margins from optimization activities of $5 million in 2006. An additional $2 million increase was primarily due to a $4 million provision for refund recorded in 2006 related to the pending and subsequent sale of our portion of the Oklaunion Plant offset in part by reduced sales margins upon completion of the sale.
- Texas Wires revenues increased $6 million primarily due to increased usage and favorable weather conditions. As compared to the prior year, heating degree days more than doubled.
- Other revenues increased $28 million. This increase was due in part to $36 million of revenue from securitization transition charges primarily resulting from new financing in October 2006. Securitization transition charges represent amounts collected to recover securitization bond principal and interest payments related to our securitized transition assets and are fully

offset by amortization and interest expenses. This increase was partially offset by a $7 million decrease in third party construction project revenues mainly related to work performed for the Lower Colorado River Authority.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $2 million primarily due to a $5 million decrease from lower expenses related to construction projects performed for third parties, primarily Lower Colorado River Authority. This decrease is partially offset by an increase of $2 million in payments made for transmission services and approximately $1 million increase related to the replacement of meters.
- Depreciation and Amortization expense increased $13 million primarily due to the recovery and amortization of the securitization assets of $15 million offset in part by $2 million related to the amortization of the CTC liability (see "TCC's 2006 Securitization Proceeding" and "TCC's 2006 CTC Proceeding" sections of Note 4 of the 2006 Annual Report).
- Taxes Other Than Income Taxes decreased $2 million primarily due to lower property-related taxes related to Texas tax legislation and the sale of our portion of Oklaunion in February 2007.
- Carrying Costs Income decreased $19 million primarily due to the absence of carrying cost on stranded cost recovery.
- Other Income increased $5 million primarily due to larger invested balances in the Utility Money Pool.
- Interest Expense increased $19 million primarily due to a $22 million increase in long-term debt interest primarily related to the Securitization Bonds issued in October 2006, offset in part by the retirement of other long-term debt.

Income Taxes

Income Tax Expense remained relatively flat for the first quarter 2007.

Financial Condition

Credit Ratings

In April 2007, Fitch Ratings downgraded our unsecured debt from A- to BBB+ and placed us on negative outlook. The negative rating outlook reflects Fitch's expectation that credit metrics will continue to be weak for the BBB rating category absent a favorable outcome in our pending rate case in Texas. See "TCC and TNC Energy Delivery Base Rate Filings" in Note 3.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in our 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $228 million and $232 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

		2007		2006
REVENUES				
Electric Generation, Transmission and Distribution	$	171,987	$	123,211
Sales to AEP Affiliates		1,130		1,598
Other		3,814		10,479
TOTAL		176,931		135,288
EXPENSES				
Fuel and Other Consumables Used for Electric Generation		825		1,726
Purchased Electricity for Resale		1,509		1,680
Other Operation		57,396		58,902
Maintenance		7,785		7,789
Depreciation and Amortization		46,020		33,360
Taxes Other Than Income Taxes		18,524		20,363
TOTAL		132,059		123,820
OPERATING INCOME		44,872		11,468
Other Income (Expense):				
Interest Income		4,959		505
Carrying Costs Income		-		19,423
Allowance for Equity Funds Used During Construction		1,159		373
Interest Expense		(46,021)		(26,773)
INCOME BEFORE INCOME TAXES		4,969		4,996
Income Tax Expense		1,431		1,223
NET INCOME		3,538		3,773
Preferred Stock Dividend Requirements		60		60
EARNINGS APPLICABLE TO COMMON STOCK	$	3,478	$	3,713

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 55,292	$ 132,606	$ 760,884	$ (1,152)	$ 947,630
Preferred Stock Dividends			(60)		(60)
TOTAL					947,570
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $141				262	262
NET INCOME			3,773		3,773
TOTAL COMPREHENSIVE INCOME					4,035
MARCH 31, 2006	$ 55,292	$ 132,606	$ 764,597	$ (890)	$ 951,605
DECEMBER 31, 2006	$ 55,292	$ 132,606	$ 217,218	$ -	$ 405,116
FIN 48 Adoption, Net of Tax			(2,187)		(2,187)
Preferred Stock Dividends			(60)		(60)
TOTAL					402,869
COMPREHENSIVE INCOME					
NET INCOME			3,538		3,538
TOTAL COMPREHENSIVE INCOME					3,538
MARCH 31, 2007	$ 55,292	$ 132,606	$ 218,509	$ -	$ 406,407

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 52	$ 779
Other Cash Deposits	131,824	104,203
Advances to Affiliates	216,953	394,004
Accounts Receivable:		
Customers	44,519	31,215
Affiliated Companies	6,513	8,613
Accrued Unbilled Revenues	17,969	10,093
Allowance for Uncollectible Accounts	(45)	(49)
Total Accounts Receivable	68,956	49,872
Materials and Supplies	30,526	28,347
Prepayments and Other	11,107	5,672
TOTAL	459,418	582,877
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	917,708	904,527
Distribution	1,602,745	1,579,498
Other	224,856	220,028
Construction Work in Progress	166,300	165,979
Total	2,911,609	2,870,032
Accumulated Depreciation and Amortization	636,740	630,239
TOTAL - NET	2,274,869	2,239,793
OTHER NONCURRENT ASSETS		
Regulatory Assets	187,765	193,111
Securitized Transition Assets	2,133,966	2,158,408
Employee Benefits and Pension Assets	35,534	35,574
Deferred Charges and Other	68,393	69,493
TOTAL	2,425,658	2,456,586
Assets Held for Sale - Texas Generation Plant	-	44,475
TOTAL ASSETS	$ 5,159,945	$ 5,323,731

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Accounts Payable:		
General	$ 17,857	$ 26,934
Affiliated Companies	17,329	21,234
Long-term Debt Due Within One Year - Nonaffiliated	138,507	78,227
Customer Deposits	17,851	18,742
Accrued Taxes	33,474	74,499
Accrued Interest	57,625	44,712
Other	21,138	34,762
TOTAL	303,781	299,110
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	2,845,020	2,937,387
Deferred Income Taxes	1,037,080	1,034,123
Regulatory Liabilities and Deferred Investment Tax Credits	503,627	598,027
Deferred Credits and Other	58,109	44,047
TOTAL	4,443,836	4,613,584
TOTAL LIABILITIES	4,747,617	4,912,694
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,921	5,921
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - Par Value - $25 Per Share:		
Authorized - 12,000,000 Shares		
Outstanding - 2,211,678 Shares	55,292	55,292
Paid-in Capital	132,606	132,606
Retained Earnings	218,509	217,218
TOTAL	406,407	405,116
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,159,945	$ 5,323,731

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 3,538	$ 3,773
Adjustments for Noncash Items:		
Depreciation and Amortization	46,020	33,360
Deferred Income Taxes	11,102	2,928
Carrying Costs on Stranded Cost Recovery	-	(19,423)
Mark-to-Market of Risk Management Contracts	-	5,125
Fuel Over/Under Recovery, Net	(98,665)	-
Deferred Property Taxes	(20,064)	(25,755)
Change in Other Noncurrent Assets	(753)	(1,330)
Change in Other Noncurrent Liabilities	3,187	1,398
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(19,084)	121,367
Fuel, Materials and Supplies	(2,543)	(2,569)
Accounts Payable	(3,957)	(53,124)
Customer Deposits	(891)	(6,514)
Accrued Taxes, Net	(40,642)	6,854
Accrued Interest	11,019	(16,152)
Other Current Assets	681	2,629
Other Current Liabilities	(13,867)	(7,461)
Net Cash Flows From (Used for) Operating Activities	(124,919)	45,106
INVESTING ACTIVITIES		
Construction Expenditures	(59,872)	(58,645)
Change in Other Cash Deposits, Net	(6,071)	29,736
Change in Advances to Affiliates, Net	177,051	(32,101)
Proceeds from Sale of Assets	45,619	3,837
Net Cash Flows From (Used For) Investing Activities	156,727	(57,173)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Affiliated	-	125,000
Change in Advances from Affiliates, Net	-	(82,080)
Retirement of Long-term Debt - Nonaffiliated	(32,125)	(30,641)
Principal Payments for Capital Lease Obligations	(350)	(152)
Dividends Paid on Cumulative Preferred Stock	(60)	(60)
Net Cash From (Used For) Financing Activities	(32,535)	12,067
Net Decrease in Cash and Cash Equivalents	(727)	-
Cash and Cash Equivalents at Beginning of Period	779	-
Cash and Cash Equivalents at End of Period	$ 52	$ -
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 27,961	$ 40,646

Net Cash Paid for Income Taxes	32,601	485
Noncash Acquisitions Under Capital Leases	363	680
Construction Expenditures Included in Accounts Payable at March 31,	7,477	9,970

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to TCC'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 TCC.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 4
Changes in Gross Margin:		
Off-system Sales	3	
Texas Wires	2	
Transmission Revenues	1	
Total Change in Gross Margin		6
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(4)	
Total Change in Operating Expenses and Other		(4)
Income Tax Expense		(1)
First Quarter of 2007		$ 5

Net Income increased $1 million primarily due to an increase in Gross Margin of $6 million partially offset by an increase in Other Operation and Maintenance expenses of $4 million.

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

- Margins from Off-system Sales increased $3 million primarily due to lower margins from optimization activities of $2 million in 2006. An additional $1 million increase was primarily due to the implementation of the Power Purchase Agreement with AEP Energy Partners in January 2007. Under this agreement, we recover our costs and capacity charges regardless of plant availability. See "Oklaunion PPA between TNC and AEP Energy Partners" section of Note 1.
- Texas Wires revenues increased $2 million primarily due to increased usage and favorable weather conditions. As compared to the prior year, heating degree days increased 77%.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $4 million primarily resulting from planned and forced outages at our Oklaunion Plant during the first quarter of 2007.

Income Taxes

Income Tax Expense increased $1 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 our 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management assets and liabilities are zero at March 31, 2007 as a result of our exit from the generation business. See "Oklaunion PPA between TNC and AEP Energy Partners" section of Note 1.

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $11 million and $12 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

		2007		2006
REVENUES				
Electric Generation, Transmission and Distribution	$	38,079	$	68,825
Sales to AEP Affiliates		24,654		6,025
Other		230		(184)
TOTAL		62,963		74,666
EXPENSES				
Fuel and Other Consumables Used for Electric Generation		6,276		12,115
Purchased Electricity for Resale		2,802		14,396
Other Operation		19,563		18,478
Maintenance		7,467		5,201
Depreciation and Amortization		10,346		10,301
Taxes Other Than Income Taxes		4,841		5,540
TOTAL		51,295		66,031
OPERATING INCOME		11,668		8,635
Other Income (Expense):				
Interest Income		133		219
Allowance for Equity Funds Used During Construction		52		382
Interest Expense		(4,346)		(4,362)
INCOME BEFORE INCOME TAXES		7,507		4,874
Income Tax Expense		2,230		1,040
NET INCOME		5,277		3,834
Preferred Stock Dividend Requirements		26		26
Gain on Reacquired Preferred Stock		-		2
EARNINGS APPLICABLE TO COMMON STOCK	$	5,251	$	3,810

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 137,214	$ 2,351	$ 174,858	$ (504)	$ 313,919
Common Stock Dividends			(8,000)		(8,000)
Preferred Stock Dividends			(26)		(26)
Gain on Reacquired Preferred Stock			2		2
TOTAL					305,895
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $102				189	189
NET INCOME			3,834		3,834
TOTAL COMPREHENSIVE INCOME					4,023
MARCH 31, 2006	$ 137,214	$ 2,351	$ 170,668	$ (315)	$ 309,918
DECEMBER 31, 2006	$ 137,214	$ 2,351	$ 176,950	$ (10,159)	$ 306,356
FIN 48 Adoption, Net of Tax			(557)		(557)
Preferred Stock Dividends			(26)		(26)
TOTAL					305,773
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $378				702	702
NET INCOME			5,277		5,277
TOTAL COMPREHENSIVE INCOME					5,979
MARCH 31, 2007	$ 137,214	$ 2,351	$ 181,644	$ (9,457)	$ 311,752

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3	$ 84
Other Cash Deposits	8,958	8,863
Advances to Affiliates	-	13,543
Accounts Receivable:		
Customers	11,080	21,742
Affiliated Companies	13,177	5,634
Accrued Unbilled Revenues	2,917	2,292
Allowance for Uncollectible Accounts	(18)	(9)
Total Accounts Receivable	27,156	29,659
Fuel	11,401	8,559
Materials and Supplies	9,544	9,319
Prepayments and Other	1,879	1,681
TOTAL	58,941	71,708
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	290,654	290,485
Transmission	330,272	327,845
Distribution	506,752	512,265
Other	160,141	159,451
Construction Work in Progress	36,145	38,847
Total	1,323,964	1,328,893
Accumulated Depreciation and Amortization	483,960	486,961
TOTAL - NET	840,004	841,932
OTHER NONCURRENT ASSETS		
Regulatory Assets	38,356	38,402
Employee Benefits and Pension Assets	12,824	12,867
Deferred Charges and Other	12,807	2,605
TOTAL	63,987	53,874
TOTAL ASSETS	$ 962,932	$ 967,514

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 11,185	$ -
Accounts Payable:		
General	6,328	4,448
Affiliated Companies	34,129	43,993
Long-term Debt Due Within One Year - Nonaffiliated	8,151	8,151
Accrued Taxes	19,477	21,782
Other	8,687	14,934
TOTAL	87,957	93,308
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	268,807	268,785
Long-term Risk Management Liabilities	-	1,081
Deferred Income Taxes	120,261	124,048
Regulatory Liabilities and Deferred Investment Tax Credits	132,646	139,429
Deferred Credits and Other	39,160	32,158
TOTAL	560,874	565,501
TOTAL LIABILITIES	648,831	658,809
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,349	2,349
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - Par Value - $25 Per Share:		
Authorized - 7,800,000 Shares		
Outstanding - 5,488,560 Shares	137,214	137,214
Paid-in Capital	2,351	2,351
Retained Earnings	181,644	176,950
Accumulated Other Comprehensive Income (Loss)	(9,457)	(10,159)
TOTAL	311,752	306,356
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 962,932	$ 967,514

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 5,277	$ 3,834
Adjustments for Noncash Items:		
Depreciation and Amortization	10,346	10,301
Deferred Income Taxes	(1,016)	(1,323)
Mark-to-Market of Risk Management Contracts	-	1,989
Deferred Property Taxes	(10,862)	(12,360)
Change in Other Noncurrent Assets	1,508	(2,081)
Change in Other Noncurrent Liabilities	(5,713)	652
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	2,503	36,836
Fuel, Materials and Supplies	(3,067)	(2,156)
Accounts Payable	(9,176)	(36,932)
Accrued Taxes, Net	(302)	4,059
Other Current Assets	(255)	1,676
Other Current Liabilities	(5,975)	(9,775)
Net Cash Flows Used For Operating Activities	(16,732)	(5,280)
INVESTING ACTIVITIES		
Construction Expenditures	(19,793)	(18,662)
Change in Other Cash Deposits, Net	(95)	792
Change In Advances to Affiliates, Net	13,543	31,240
Proceeds from Sale of Assets	11,965	-
Net Cash Flows From Investing Activities	5,620	13,370
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	11,185	-
Principal Payments for Capital Lease Obligations	(128)	(64)
Dividends Paid on Common Stock	-	(8,000)
Dividends Paid on Cumulative Preferred Stock	(26)	(26)
Net Cash Flows From (Used For) Financing Activities	11,031	(8,090)
Net Decrease in Cash and Cash Equivalents	(81)	-
Cash and Cash Equivalents at Beginning of Period	84	-
Cash and Cash Equivalents at End of Period	$ 3	$ -
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 6,150	$ 6,113
Net Cash Paid for Income Taxes	2,288	-
Noncash Acquisitions Under Capital Leases	98	224
Construction Expenditures Included in Accounts Payable at March 31,	2,509	2,372

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to TNC'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 TNC.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 74
Changes in Gross Margin:		
Retail Margins	29	
Off-system Sales	(6)	
Transmission Revenues	(11)	
Other	1	
Total Change in Gross Margin		13
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(5)	
Depreciation and Amortization	(11)	
Taxes Other Than Income Taxes	2	
Carrying Costs Income	(3)	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(19)
Income Tax Expense		2
First Quarter of 2007		$ 70

Net Income decreased $4 million to $70 million in 2007 primarily due to an increase in Operating Expenses and Other of $19 million, partially offset by an increase in Gross Margin of $13 million.

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

- Retail Margins increased $29 million in comparison to 2006 primarily due to:
  - A $42 million increase in retail revenues primarily related to new rates implemented in relation to our Virginia general rate case, which are being collected subject to refund, and recovery of Virginia Environmental and Reliability (E&R) costs. See the "APCo Virginia Base Rate Case" section of Note 3.
  - A $9 million increase in retail sales primarily due to increased demand in the residential class associated with favorable weather conditions. Heating degree days increased approximately 19%.

  These increases were partially offset by:

- A $14 million decrease in revenues related to financial transmission rights, net of congestion, primarily due to fewer transmission constraints in the PJM market.
- A $9 million decrease in revenues related to the Expanded Net Energy Cost (ENEC) mechanism with West Virginia retail customers primarily due to pass-through of off-system sales margins. The mechanism was reinstated in West Virginia effective July 1, 2006 in conjunction with our West Virginia rate case.

- Margins from Off-system Sales decreased $6 million primarily due to an $18 million decrease in physical sales margins partially offset by a $10 million increase in margins from optimization activities and a $2 million increase in our allocation of off-system sales margins under the SIA. The change in allocation methodology of the SIA occurred on April 1, 2006.
- Transmission Revenues decreased $11 million primarily due to the elimination of SECA revenues as of April 1, 2006. See the "Transmission Rate Proceedings at the FERC" section of Note 3.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $5 million mainly due to a $6 million increase in expenses for overhead line right-of-way clearing, overhead line repairs and increases in various other operation and maintenance expenses totaling $8 million. These increases were partially offset by a $9 million decrease in expenses related to the AEP Transmission Equalization Agreement due to the addition of our Wyoming-Jacksons Ferry 765 kV line which was energized and placed into service in June 2006.
- Depreciation and Amortization expenses increased $11 million primarily due to the amortization of carrying charges and depreciation expense that are being collected through the E&R surcharges and increased plant in service related to the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.
- Carrying Costs Income decreased $3 million related to carrying costs associated with our E&R case.

Income Taxes

Income Tax Expense decreased $2 million primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. 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, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
	$ 2,318	$ 1,741

Cash and Cash Equivalents at Beginning of Period		
Cash Flows From (Used For):		
Operating Activities	176,029	210,980
Investing Activities	(200,894)	(194,897)
Financing Activities	24,534	(16,372)
Net Decrease in Cash and Cash Equivalents	(331)	(289)
Cash and Cash Equivalents at End of Period	$ 1,987	$ 1,452

Operating Activities

Net Cash Flows From Operating Activities were $176 million in 2007. We 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 current period activity in working capital had no significant items in 2007.

Net Cash Flows From Operating Activities were $211 million in 2006. We produced income of $74 million during the period and a noncash expense item of $48 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 had two significant items, an increase in Accounts Receivable, Net and Accrued Taxes, Net. During the first quarter of 2006, we did not make any federal income tax payments and collected receivables from our affiliates related to power sales, settled litigation and emission allowances.

Investing Activities

Net Cash Flows Used For Investing Activities during 2007 and 2006 primarily reflect our construction expenditures of $202 million and $197 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades for both periods. In 2006, capital projects for transmission expenditures were primarily related to the Wyoming-Jacksons Ferry 765 KV line placed into service in June 2006. Environmental upgrades include the installation of selective catalytic reduction equipment on our plants and the flue gas desulfurization project at the Amos and Mountaineer plants. In February 2007, environmental upgrades were completed for the Mountaineer plant. For the remainder of 2007, we expect construction expenditures to be approximately $460 million.

Financing Activities

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

Net Cash Flows Used For Financing Activities were $16 million in 2006. In 2006, we retired a First Mortgage Bond of $100 million and incurred obligations of $50 million relating to pollution control bonds. We repaid short-term borrowings from the Utility Money Pool of $30 million. In addition, we received funds of $68 million related to a long-term coal purchase contract amended in March 2006.

Financing Activity

There were no material long-term debt issuances and retirements during the first three months of 2007.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2006 Annual Report and has not changed significantly from year-end.

Significant Factors

New Generation

In January 2006, we filed a petition with the WVPSC requesting our approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to our existing Mountaineer Generating Station in Mason County, WV. In January 2007, at our request, the WVPSC issued an order delaying the Commission's deadline for issuing an order on the certificate to December 2007. Through March 31, 2007, we deferred pre-construction IGCC costs totaling $10 million. If the plant is not built and these costs are not recoverable, future results of operations and cash flows would be adversely affected.

Virginia Restructuring

In April 2004, Virginia enacted legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides us with specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, we continue to have an active fuel clause recovery mechanism in Virginia and continue to practice deferred fuel accounting. Also, under the restructuring law, we defer incremental environmental generation costs and incremental transmission and distribution reliability costs for future recovery, to the extent such costs are not being recovered when incurred, and amortize a portion of such deferrals commensurate with recovery.

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation/supply rates. The amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation/supply will return to a form of cost-based regulation. The legislation provides for, among other things, biennial rate reviews beginning in 2009, rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investment, (b) Demand Side Management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments, significant return on equity enhancements for large investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, the amendments allow utilities to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses. The legislation also allows us to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. We expect this new form of cost-based ratemaking should improve our annual return on equity and cash flow from operations when new ratemaking begins in 2009. However, with the return of cost-based regulation, our generation business will again meet the criteria for application of regulatory accounting principles under SFAS 71. Results of operations and financial condition could be adversely affected when we are required to re-establish certain net regulatory liabilities applicable to our generation/supply business. The timing and earnings effect from such reapplication of SFAS 71 regulatory accounting for our Virginia generation/supply business are uncertain at this time.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome 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 our pending litigation and regulatory proceedings, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in our 2006 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. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management assets and liabilities are managed by AEPSC as agent for us. 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 us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included on our condensed consolidated balance sheet as of March 31, 2007 and the reasons for changes in our total MTM value as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of March 31, 2007 (in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 66,058	$ 1,405	$ -	$ 67,463
Noncurrent Assets	84,718	1,269	-	85,987
Total MTM Derivative Contract Assets	150,776	2,674	-	153,450
Current Liabilities	(47,767)	(6,899)	(3,152)	(57,818)
Noncurrent Liabilities	(49,833)	(804)	(8,358)	(58,995)
Total MTM Derivative Contract Liabilities	(97,600)	(7,703)	(11,510)	(116,813)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 53,176	$ (5,029)	$ (11,510)	$ 36,637

(a) See "Natural Gas Contracts with DETM" section of Note 16 of the 2006 Annual Report.

MTM Risk Management Contract Net Assets Three Months Ended March 31, 2007 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 52,489
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(5,389)
Fair Value of New Contracts at Inception When Entered During the Period (a)	255
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(35)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	4,918
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	938
Total MTM Risk Management Contract Net Assets	53,176

Net Cash Flow & Fair Value Hedge Contracts		(5,029)
DETM Assignment (d)		(11,510)
Total MTM Risk Management Contract Net Assets at March 31, 2007	$	36,637

(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) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 16 of the 2006 Annual Report.

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

The following table presents:

· The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
· 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
Fair Value of Contracts as of March 31, 2007
(in thousands)

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted - Exchange Traded Contracts	$ 15,650	$ (644)	$ 706	$ -	$ -	$ -	$ 15,712
Prices Provided by Other External Sources - OTC Broker Quotes (a)	3,482	13,908	11,448	4,542	-	-	33,380
Prices Based on Models and Other Valuation Methods (b)	(3,723)	(2,358)	1,822	5,482	1,235	1,626	4,084
Total	$ 15,409	$ 10,906	$ 13,976	$ 10,024	$ 1,235	$ 1,626	$ 53,176

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in

the modeled category varies by market.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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

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 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 anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We use forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. 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 the changes from December 31, 2006 to March 31, 2007. 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, 2007
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2006	$ 5,332	$ (164)	$ (7,715)	$ (2,547)
Changes in Fair Value	(5,612)	-	-	(5,612)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(2,221)	2	347	(1,872)
Ending Balance in AOCI March 31, 2007	$ (2,501)	$ (162)	$ (7,368)	$ (10,031)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $4,214 thousand loss.

Credit Risk

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

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, 2007, 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:

Three Months Ended March 31, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$712	$2,328	$1,037	$282	$756	$1,915	$658	$358

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $176 million and $153 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
REVENUES		
Electric Generation, Transmission and Distribution	$ 601,546	$ 559,993
Sales to AEP Affiliates	61,545	71,772
Other	2,637	2,676
TOTAL	665,728	634,441
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	171,186	166,853
Purchased Electricity for Resale	35,950	27,616
Purchased Electricity from AEP Affiliates	127,601	122,399
Other Operation	67,629	69,901
Maintenance	45,753	37,839
Depreciation and Amortization	59,160	48,268
Taxes Other Than Income Taxes	21,275	23,092
TOTAL	528,554	495,968
OPERATING INCOME	137,174	138,473
Other Income (Expense):		
Interest Income	639	951
Carrying Costs Income	3,166	6,011
Allowance for Equity Funds Used During Construction	2,777	2,476
Interest Expense	(31,823)	(30,268)
INCOME BEFORE INCOME TAXES	111,933	117,643
Income Tax Expense	41,706	44,049
NET INCOME	70,227	73,594
Preferred Stock Dividend Requirements including Capital Stock Expense	238	238
EARNINGS APPLICABLE TO COMMON STOCK	$ 69,989	$ 73,356

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 260,458	$ 924,837	$ 635,016	$ (16,610)	$ 1,803,701
Common Stock Dividends			(2,500)		(2,500)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		38	(38)		-
TOTAL					1,801,001
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,144				13,268	13,268
NET INCOME			73,594		73,594
TOTAL COMPREHENSIVE INCOME					86,862
MARCH 31, 2006	$ 260,458	$ 924,875	$ 705,872	$ (3,342)	$ 1,887,863
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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,987	$ 2,318
Accounts Receivable:		
Customers	199,112	180,190
Affiliated Companies	85,919	98,237
Accrued Unbilled Revenues	29,618	46,281
Miscellaneous	4,849	3,400
Allowance for Uncollectible Accounts	(4,573)	(4,334)
Total Accounts Receivable	314,925	323,774
Fuel	72,075	77,077
Materials and Supplies	69,428	56,235
Risk Management Assets	67,463	105,376
Accrued Tax Benefits	9,189	3,748
Regulatory Asset for Under-Recovered Fuel Costs	17,789	29,526
Prepayments and Other	15,682	20,126
TOTAL	568,538	618,180
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,363,911	2,844,803
Transmission	1,640,046	1,620,512
Distribution	2,276,327	2,237,887
Other	342,014	339,450
Construction Work in Progress	512,388	957,626
Total	8,134,686	8,000,278
Accumulated Depreciation and Amortization	2,470,106	2,476,290
TOTAL - NET	5,664,580	5,523,988
OTHER NONCURRENT ASSETS		
Regulatory Assets	612,352	622,153
Long-term Risk Management Assets	85,987	88,906
Deferred Charges and Other	167,913	163,089
TOTAL	866,252	874,148
TOTAL ASSETS	$ 7,099,370	$ 7,016,316

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 82,860	$ 34,975
Accounts Payable:		
General	286,892	296,437
Affiliated Companies	77,642	105,525
Long-term Debt Due Within One Year - Nonaffiliated	324,169	324,191
Risk Management Liabilities	57,818	81,114
Customer Deposits	54,193	56,364
Accrued Taxes	87,864	60,056
Accrued Interest	55,787	30,617
Other	119,509	142,326
TOTAL	1,146,734	1,131,605
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	2,174,951	2,174,473
Long-term Debt - Affiliated	100,000	100,000
Long-term Risk Management Liabilities	58,995	64,909
Deferred Income Taxes	933,703	957,229
Regulatory Liabilities and Deferred Investment Tax Credits	307,018	309,724
Deferred Credits and Other	279,174	224,439
TOTAL	3,853,841	3,830,774
TOTAL LIABILITIES	5,000,575	4,962,379
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,763	17,763
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	1,025,032	1,024,994
Retained Earnings	857,817	805,513
Accumulated Other Comprehensive Income (Loss)	(62,275)	(54,791)
TOTAL	2,081,032	2,036,174
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,099,370	$ 7,016,316

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 70,227	$ 73,594
Adjustments for Noncash Items:		
Depreciation and Amortization	59,160	48,268
Deferred Income Taxes	(3,901)	(11,423)
Carrying Costs Income	(3,166)	(6,011)
Mark-to-Market of Risk Management Contracts	(401)	(5,696)
Change in Other Noncurrent Assets	(12,747)	4,020
Change in Other Noncurrent Liabilities	30,172	5,848
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	8,849	75,278
Fuel, Materials and Supplies	(1,034)	13,028
Accounts Payable	(19,891)	(30,148)
Customer Deposits	(2,171)	(13,530)
Accrued Taxes, Net	29,539	56,180
Accrued Interest	21,608	15,511
Fuel Over/Under Recovery, Net	12,987	7,832
Other Current Assets	3,899	(1,718)
Other Current Liabilities	(17,101)	(20,053)
Net Cash Flows From Operating Activities	176,029	210,980
INVESTING ACTIVITIES		
Construction Expenditures	(202,007)	(196,561)
Change in Other Cash Deposits, Net	(29)	-
Proceeds from Sales of Assets	1,142	1,664
Net Cash Flows Used For Investing Activities	(200,894)	(194,897)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	-	49,677
Change in Advances from Affiliates, Net	47,885	(29,941)
Retirement of Long-term Debt - Nonaffiliated	(3)	(100,003)
Principal Payments for Capital Lease Obligations	(1,112)	(1,483)
Funds From Amended Coal Contract	-	68,078
Amortization of Funds From Amended Coal Contract	(7,036)	-
Dividends Paid on Common Stock	(15,000)	(2,500)
Dividends Paid on Cumulative Preferred Stock	(200)	(200)
Net Cash Flows From (Used For) Financing Activities	24,534	(16,372)
Net Decrease in Cash and Cash Equivalents	(331)	(289)
Cash and Cash Equivalents at Beginning of Period	2,318	1,741
Cash and Cash Equivalents at End of Period	$ 1,987	$ 1,452

SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	7,084	$	14,686
Net Cash Paid for Income Taxes		7,775		1,771
Noncash Acquisitions Under Capital Leases		444		1,184
Construction Expenditures Included in Accounts Payable at March 31,		113,021		83,682

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 51
Changes in Gross Margin:		
Retail Margins	27	
Off-system Sales	(11)	
Transmission Revenues	(7)	
Other	(4)	
Total Change in Gross Margin		5
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(10)	
Depreciation and Amortization	(4)	
Taxes Other Than Income Taxes	(1)	
Interest Expense	2	
Other	1	
Total Change in Operating Expenses and Other		(12)
Income Tax Expense		3
First Quarter of 2007		$ 47

Net Income decreased $4 million to $47 million in 2007. The key driver of the decrease was a $12 million increase in Operating Expenses and Other offset by a $5 million increase in Gross Margin and a $3 million decrease in Income Tax Expense.

The major components of our 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 $27 million primarily due to:
  · An $11 million increase in residential and commercial revenue primarily due to a 27% increase in heating degree days.
  · A $10 million increase in rate revenues related to a $4 million increase in our RSP, a $3 million increase related to rate recovery of storm costs and a $3 million increase related to rate recovery of IGCC preconstruction costs (see "Ohio Rate Matters" section of Note 3). The increase in rate recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction

costs was offset by the amortization of deferred expenses in Depreciation and Amortization.

- A $7 million increase in industrial revenue due to the addition of Ormet, a major industrial customer (see "Ormet" section of Note 3).

- Margins from Off-system Sales decreased $11 million primarily due to an $8 million decrease in physical sales margins and a $4 million decrease in margins from optimization activities.
- Transmission Revenues decreased $7 million primarily due to the elimination of SECA revenues as of April 1, 2006. See the "Transmission Rate Proceedings at the FERC" section of Note 3.
- Other revenues decreased $4 million primarily due to lower gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $10 million primarily due to:
  - A $5 million increase in overhead line expenses due in part to the amortization of deferred storm expenses recovered through a cost-recovery rider. The increase in amortization of deferred storm expenses was offset by a corresponding increase in Retail Margins.
  - A $3 million increase in our net allocated transmission costs related to the Transmission Equalization Agreement as a result of the addition of APCo's Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.
- Depreciation and Amortization increased $4 million primarily due to the amortization of IGCC preconstruction costs of $3 million in the first quarter of 2007. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins.
- Interest Expense decreased $2 million primarily due to an increase in allowance for borrowed funds used during construction.

Income Taxes

Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income and state income taxes offset in part by the recording of tax adjustments.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in our 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $80 million and $70 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
REVENUES		
Electric Generation, Transmission and Distribution	$ 423,466	$ 413,669
Sales to AEP Affiliates	23,013	13,769
Other	1,433	1,330
TOTAL	447,912	428,768
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	75,862	69,820
Purchased Electricity for Resale	31,311	24,765
Purchased Electricity from AEP Affiliates	83,541	82,477
Other Operation	61,159	55,945
Maintenance	22,564	17,934
Depreciation and Amortization	50,297	45,828
Taxes Other Than Income Taxes	40,582	39,502
TOTAL	365,316	336,271
OPERATING INCOME	82,596	92,497
Other Income (Expense):		
Interest Income	422	455
Carrying Costs Income	1,092	716
Allowance for Equity Funds Used During Construction	772	464
Interest Expense	(15,281)	(17,520)
INCOME BEFORE INCOME TAXES	69,601	76,612
Income Tax Expense	22,620	25,275
NET INCOME	46,981	51,337
Capital Stock Expense	39	39
EARNINGS APPLICABLE TO COMMON STOCK	$ 46,942	$ 51,298

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 41,026	$ 580,035	$ 361,365	$ (880)	$ 981,546
Common Stock Dividends			(22,500)		(22,500)
Capital Stock Expense		39	(39)		-
TOTAL					959,046
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,176				4,041	4,041
NET INCOME			51,337		51,337
TOTAL COMPREHENSIVE INCOME					55,378
MARCH 31, 2006	$ 41,026	$ 580,074	$ 390,163	$ 3,161	$ 1,014,424
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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 237	$ 1,319
Advances to Affiliates	922	-
Accounts Receivable:		
Customers	59,380	49,362
Affiliated Companies	35,351	62,866
Accrued Unbilled Revenues	8,011	11,042
Miscellaneous	5,626	4,895
Allowance for Uncollectible Accounts	(588)	(546)
Total Accounts Receivable	107,780	127,619
Fuel	31,320	37,348
Materials and Supplies	34,575	31,765
Emission Allowances	8,971	3,493
Risk Management Assets	36,969	66,238
Accrued Tax Benefits	-	4,763
Prepayments and Other	11,734	16,107
TOTAL	232,508	288,652
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,954,377	1,896,073
Transmission	481,875	479,119
Distribution	1,496,080	1,475,758
Other	190,645	191,103
Construction Work in Progress	269,771	294,138
Total	4,392,748	4,336,191
Accumulated Depreciation and Amortization	1,629,386	1,611,043
TOTAL - NET	2,763,362	2,725,148
OTHER NONCURRENT ASSETS		
Regulatory Assets	277,251	298,304
Long-term Risk Management Assets	46,978	56,206
Deferred Charges and Other	131,818	152,379
TOTAL	456,047	506,889
TOTAL ASSETS	$ 3,451,917	$ 3,520,689

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 696
Accounts Payable:		
General	97,767	112,431
Affiliated Companies	51,552	59,538
Long-term Debt Due Within One Year - Nonaffiliated	52,000	-
Risk Management Liabilities	31,365	49,285
Customer Deposits	37,563	34,991
Accrued Taxes	144,223	166,551
Accrued Interest	17,698	20,868
Other	34,767	37,143
TOTAL	466,935	481,503
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	1,045,422	1,097,322
Long-term Debt - Affiliated	100,000	100,000
Long-term Risk Management Liabilities	32,396	40,477
Deferred Income Taxes	462,516	475,888
Regulatory Liabilities and Deferred Investment Tax Credits	168,597	179,048
Deferred Credits and Other	101,351	90,434
TOTAL	1,910,282	1,983,169
TOTAL LIABILITIES	2,377,217	2,464,672
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	580,231	580,192
Retained Earnings	480,707	456,787
Accumulated Other Comprehensive Income (Loss)	(27,264)	(21,988)
TOTAL	1,074,700	1,056,017
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,451,917	$ 3,520,689

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 46,981	$ 51,337
Adjustments for Noncash Items:		
Depreciation and Amortization	50,297	45,828
Deferred Income Taxes	(716)	3,816
Carrying Costs Income	(1,092)	(716)
Mark-to-Market of Risk Management Contracts	4,400	(3,624)
Deferred Property Taxes	18,954	10,884
Change in Other Noncurrent Assets	(912)	(11,325)
Change in Other Noncurrent Liabilities	(15,510)	5,800
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	19,839	33,295
Fuel, Materials and Supplies	3,218	(7,431)
Accounts Payable	(7,659)	12,540
Customer Deposits	2,572	(7,901)
Accrued Taxes, Net	(8,651)	(7,873)
Accrued Interest	(5,658)	(4,127)
Other Current Assets	5,694	(728)
Other Current Liabilities	(5,056)	(6,571)
Net Cash Flows From Operating Activities	106,701	113,204
INVESTING ACTIVITIES		
Construction Expenditures	(85,641)	(65,032)
Change in Other Cash Deposits, Net	(20)	(1,151)
Change in Advances to Affiliates, Net	(922)	(6,867)
Proceeds from Sale of Assets	189	531
Net Cash Flows Used For Investing Activities	(86,394)	(72,519)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(696)	(17,609)
Principal Payments for Capital Lease Obligations	(693)	(759)
Dividends Paid on Common Stock	(20,000)	(22,500)
Net Cash Flows Used For Financing Activities	(21,389)	(40,868)
Net Decrease in Cash and Cash Equivalents	(1,082)	(183)
Cash and Cash Equivalents at Beginning of Period	1,319	940
Cash and Cash Equivalents at End of Period	$ 237	$ 757
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 20,132	$ 22,320
Net Cash Paid (Received) for Income Taxes	(2,907)	2,533
Noncash Acquisitions Under Capital Leases	275	1,102
Construction Expenditures Included in Accounts Payable at March 31,	20,636	12,054

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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.

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 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 58
Changes in Gross Margin:		
Retail Margins	(24)	
FERC Municipals and Cooperatives	9	
Off-system Sales	(4)	
Transmission Revenues	(2)	
Other	(7)	
Total Change in Gross Margin		(28)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(6)	
Depreciation and Amortization	(7)	
Other Income	(1)	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(16)
Income Tax Expense		15
First Quarter of 2007		$ 29

Net Income decreased $29 million to $29 million in 2007. The key driver of the decrease was a $28 million decrease in Gross Margin.

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

- Retail Margins decreased $24 million primarily due to a reduction in capacity settlement revenues of $23 million under the Interconnection Agreement reflecting our new peak demand in July 2006.
- FERC Municipals and Cooperatives margins increased $9 million due to the addition of new municipal contracts including new rates and increased demand effective July 2006 and January 2007.
- Margins from Off-system Sales decreased $4 million primarily due to an $11 million decrease in physical sales margins partially offset by a $6 million increase in margins from optimization activities.
-

Transmission Revenues decreased $2 million primarily due to the elimination of SECA revenues as of April 1, 2006. See the “Transmission Rate Proceedings at the FERC” section of Note 3.

- Other revenues decreased $7 million primarily due to decreased River Transportation Division (RTD) revenues for barging coal and decreased gains on sales of emission allowances. RTD related expenses which offset the RTD revenue decrease are included in Other Operation on the Condensed Consolidated Statements of Income resulting in our earning only a return approved under regulatory order.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $6 million primarily due to a $5 million increase in transmission expense due to our reduced credits under the Transmission Equalization Agreement. Our credits decreased due to our July 2006 peak and due to APCo’s addition of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006 thus decreasing our share of the transmission investment pool.
- Depreciation and Amortization expense increased $7 million primarily due to a $5 million increase in depreciation related to capital additions and a $2 million increase in amortization related to capitalized software development costs.
- Interest Expense increased $2 million primarily due to an increase in outstanding long-term debt and higher interest rates.

Income Taxes

Income Tax Expense decreased $15 million primarily due to a decrease in pretax book income.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in our 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $108 million and $93 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
REVENUES		
Electric Generation, Transmission and Distribution	$ 405,164	$ 403,769
Sales to AEP Affiliates	67,429	88,534
Other - Affiliated	12,667	15,094
Other - Nonaffiliated	7,609	8,382
TOTAL	492,869	515,779
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	96,117	89,452
Purchased Electricity for Resale	17,940	11,010
Purchased Electricity from AEP Affiliates	77,513	86,422
Other Operation	120,733	111,617
Maintenance	42,430	45,219
Depreciation and Amortization	56,307	49,715
Taxes Other Than Income Taxes	17,994	18,906
TOTAL	429,034	412,341
OPERATING INCOME	63,835	103,438
Other Income (Expense):		
Interest Income	588	694
Allowance for Equity Funds Used During Construction	265	1,924
Interest Expense	(19,821)	(17,533)
INCOME BEFORE INCOME TAXES	44,867	88,523
Income Tax Expense	15,404	30,645
NET INCOME	29,463	57,878
Preferred Stock Dividend Requirements	85	85
EARNINGS APPLICABLE TO COMMON STOCK	$ 29,378	$ 57,793

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 56,584	$ 861,290	$ 305,787	$ (3,569)	$ 1,220,092
Common Stock Dividends			(10,000)		(10,000)
Preferred Stock Dividends			(85)		(85)
TOTAL					1,210,007
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,265				4,207	4,207
NET INCOME			57,878		57,878
TOTAL COMPREHENSIVE INCOME					62,085
MARCH 31, 2006	$ 56,584	$ 861,290	$ 353,580	$ 638	$ 1,272,092
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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

		2007		2006
CURRENT ASSETS				
Cash and Cash Equivalents	$	753	$	1,369
Accounts Receivable:				
Customers		86,128		82,102
Affiliated Companies		66,155		108,288
Accrued Unbilled Revenues		806		2,206
Miscellaneous		2,571		1,838
Allowance for Uncollectible Accounts		(616)		(601)
Total Accounts Receivable		155,044		193,833
Fuel		47,818		64,669
Materials and Supplies		136,373		129,953
Risk Management Assets		39,175		69,752
Accrued Tax Benefits		8,680		27,378
Prepayments and Other		13,500		15,170
TOTAL		401,343		502,124
PROPERTY, PLANT AND EQUIPMENT				
Electric:				
Production		3,383,343		3,363,813
Transmission		1,052,730		1,047,264
Distribution		1,143,815		1,102,033
Other (including nuclear fuel and coal mining)		516,972		529,727
Construction Work in Progress		144,856		183,893
Total		6,241,716		6,226,730
Accumulated Depreciation, Depletion and Amortization		2,949,796		2,914,131
TOTAL - NET		3,291,920		3,312,599
OTHER NONCURRENT ASSETS				
Regulatory Assets		292,704		314,805
Spent Nuclear Fuel and Decommissioning Trusts		1,262,960		1,248,319
Long-term Risk Management Assets		49,470		59,137
Deferred Charges and Other		117,384		109,453
TOTAL		1,722,518		1,731,714
TOTAL ASSETS	$	5,415,781	$	5,546,437

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 45,759	$ 91,173
Accounts Payable:		
General	99,223	146,733
Affiliated Companies	57,940	65,497
Long-term Debt Due Within One Year - Nonaffiliated	50,000	50,000
Risk Management Liabilities	33,643	52,083
Customer Deposits	31,436	34,946
Accrued Taxes	76,087	59,652
Other	115,714	128,461
TOTAL	509,802	628,545
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	1,508,695	1,505,135
Long-term Risk Management Liabilities	34,243	42,641
Deferred Income Taxes	311,584	335,000
Regulatory Liabilities and Deferred Investment Tax Credits	739,972	753,402
Asset Retirement Obligations	820,371	809,853
Deferred Credits and Other	179,181	174,340
TOTAL	3,594,046	3,620,371
TOTAL LIABILITIES	4,103,848	4,248,916
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,082	8,082
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	861,290	861,290
Retained Earnings	406,321	386,616
Accumulated Other Comprehensive Income (Loss)	(20,344)	(15,051)
TOTAL	1,303,851	1,289,439
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,415,781	$ 5,546,437

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 29,463	$ 57,878
Adjustments for Noncash Items:		
Depreciation and Amortization	56,307	49,715
Deferred Income Taxes	(3,638)	3,493
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	12,191	(1,639)
Amortization of Nuclear Fuel	16,372	13,596
Mark-to-Market of Risk Management Contracts	4,897	(4,060)
Deferred Property Taxes	(10,836)	(9,839)
Change in Other Noncurrent Assets	5,729	4,381
Change in Other Noncurrent Liabilities	(1,971)	18,839
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	38,789	43,019
Fuel, Materials and Supplies	14,985	(7,194)
Accounts Payable	(38,233)	(7,010)
Customer Deposits	(3,510)	(8,031)
Accrued Taxes, Net	39,525	42,871
Accrued Rent - Rockport Plant Unit 2	18,464	18,464
Other Current Assets	1,959	428
Other Current Liabilities	(35,720)	(20,797)
Net Cash Flows From Operating Activities	144,773	194,114
INVESTING ACTIVITIES		
Construction Expenditures	(62,252)	(89,411)
Purchases of Investment Securities	(204,874)	(150,239)
Sales of Investment Securities	183,927	134,258
Acquisitions of Nuclear Fuel	(5,366)	(34,427)
Proceeds from Sales of Assets and Other	248	1,384
Net Cash Flows Used For Investing Activities	(88,317)	(138,435)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(45,414)	(44,565)
Principal Payments for Capital Lease Obligations	(1,573)	(1,274)
Dividends Paid on Common Stock	(10,000)	(10,000)
Dividends Paid on Cumulative Preferred Stock	(85)	(85)
Net Cash Flows Used For Financing Activities	(57,072)	(55,924)
Net Decrease in Cash and Cash Equivalents	(616)	(245)
Cash and Cash Equivalents at Beginning of Period	1,369	854
Cash and Cash Equivalents at End of Period	$ 753	$ 609
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 15,048	$ 4,776

Net Cash Paid (Received) for Income Taxes	(2,768)	1,324
Noncash Acquisitions Under Capital Leases	369	2,218
Construction Expenditures Included in Accounts Payable at March 31,	20,243	27,624

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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.

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 10
Changes in Gross Margin:		
Retail Margins	17	
Off-system Sales	(2)	
Transmission Revenues	(3)	
Other	(1)	
Total Change in Gross Margin		11
Other Operation and Maintenance		(3)
Income Tax Expense		(3)
First Quarter of 2007		$ 15

Net Income increased $5 million to $15 million in 2007. The key driver of the increase was an $11 million increase in Gross Margin, offset by an increase in Other Operation and Maintenance expenses of $3 million and an increase in Income Tax Expense of $3 million.

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

- Retail Margins increased $17 million primarily due to rate relief of $14 million from the March 2006 approval of the settlement agreement in our base rate case.
- Transmission Revenues decreased $3 million primarily due to the elimination of SECA revenues as of April 1, 2006. See the "Transmission Rate Proceedings at the FERC" section of Note 3.

Other Operation and Maintenance

Other Operation and Maintenance expenses increased $3 million primarily due to an increase in our net allocated transmission costs related to the Transmission Equalization Agreement as a result of the addition of APCo's Wyoming-Jacksons Ferry 765 kV line which was energized and placed into service in June 2006. Other Operation and Maintenance expenses also increased as a result of increased forced outages at the Big Sandy Plant.

Income Taxes

Income Tax Expense increased $3 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 our 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $19 million and $13 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
REVENUES		
Electric Generation, Transmission and Distribution	$ 140,486	$ 137,620
Sales to AEP Affiliates	13,461	13,968
Other	149	259
TOTAL	154,096	151,847
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	38,304	43,966
Purchased Electricity for Resale	3,305	973
Purchased Electricity from AEP Affiliates	43,257	49,526
Other Operation	15,886	13,726
Maintenance	8,210	7,141
Depreciation and Amortization	11,796	11,479
Taxes Other Than Income Taxes	2,803	2,512
TOTAL	123,561	129,323
OPERATING INCOME	30,535	22,524
Other Income (Expense):		
Interest Income	112	166
Allowance for Equity Funds Used During Construction	14	101
Interest Expense	(7,011)	(7,296)
INCOME BEFORE INCOME TAXES	23,650	15,495
Income Tax Expense	8,439	5,665
NET INCOME	$ 15,211	$ 9,830

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 50,450	$ 208,750	$ 88,864	$ (223)	$ 347,841
Common Stock Dividends			(2,500)		(2,500)
TOTAL					345,341
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $873				1,621	1,621
NET INCOME			9,830		9,830
TOTAL COMPREHENSIVE INCOME					11,451
MARCH 31, 2006	$ 50,450	$ 208,750	$ 96,194	$ 1,398	$ 356,792
DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$ 369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(5,000)		(5,000)
TOTAL					363,865
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,100				(2,042)	(2,042)
NET INCOME			15,211		15,211
TOTAL COMPREHENSIVE INCOME					13,169
MARCH 31, 2007	$ 50,450	$ 208,750	$ 118,324	$ (490)	$ 377,034

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 775	$ 702
Accounts Receivable:		
Customers	30,027	30,112
Affiliated Companies	9,142	10,540
Accrued Unbilled Revenues	6,093	3,602
Miscellaneous	684	327
Allowance for Uncollectible Accounts	(242)	(227)
Total Accounts Receivable	45,704	44,354
Fuel	12,852	16,070
Materials and Supplies	10,277	8,726
Risk Management Assets	16,110	25,624
Accrued Tax Benefits	-	1,021
Margin Deposits	1,458	2,923
Prepayments and Other	2,637	2,425
TOTAL	89,813	101,845
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	480,501	478,955
Transmission	395,646	394,419
Distribution	480,690	481,083
Other	60,047	61,089
Construction Work in Progress	27,705	29,587
Total	1,444,589	1,445,133
Accumulated Depreciation and Amortization	441,565	442,778
TOTAL - NET	1,003,024	1,002,355
OTHER NONCURRENT ASSETS		
Regulatory Assets	135,241	136,139
Long-term Risk Management Assets	19,313	21,282
Deferred Charges and Other	46,953	48,944
TOTAL	201,507	206,365
TOTAL ASSETS	$ 1,294,344	$ 1,310,565

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 20,769	$ 30,636
Accounts Payable:		
General	33,876	31,490
Affiliated Companies	17,615	23,658
Long-term Debt Due Within One Year - Nonaffiliated	322,554	322,048
Risk Management Liabilities	14,167	20,001
Customer Deposits	15,273	16,095
Accrued Taxes	18,933	18,775
Other	22,759	26,303
TOTAL	465,946	489,006
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	104,944	104,920
Long-term Debt - Affiliated	20,000	20,000
Long-term Risk Management Liabilities	13,464	15,426
Deferred Income Taxes	239,776	242,133
Regulatory Liabilities and Deferred Investment Tax Credits	47,426	49,109
Deferred Credits and Other	25,754	20,320
TOTAL	451,364	451,908
TOTAL LIABILITIES	917,310	940,914
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $50 Par Value Per Share:		
Authorized - 2,000,000 Shares		
Outstanding - 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	118,324	108,899
Accumulated Other Comprehensive Income (Loss)	(490)	1,552
TOTAL	377,034	369,651
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,294,344	$ 1,310,565

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 15,211	$ 9,830
Adjustments for Noncash Items:		
Depreciation and Amortization	11,796	11,479
Deferred Income Taxes	956	2,217
Mark-to-Market of Risk Management Contracts	1,092	(1,378)
Change in Other Noncurrent Assets	980	2,518
Change in Other Noncurrent Liabilities	(78)	1,845
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(1,350)	16,149
Fuel, Materials and Supplies	3,609	(2,808)
Accounts Payable	(2,557)	(6,212)
Customer Deposits	(822)	(3,127)
Accrued Taxes, Net	1,447	2,676
Other Current Assets	1,012	2,069
Other Current Liabilities	(3,348)	(1,480)
Net Cash Flows From Operating Activities	27,948	33,778
INVESTING ACTIVITIES		
Construction Expenditures	(13,001)	(19,376)
Change in Advances to Affiliates, Net	-	(5,923)
Proceeds from Sale of Assets	231	301
Net Cash Flows Used For Investing Activities	(12,770)	(24,998)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(9,867)	(6,040)
Principal Payments for Capital Lease Obligations	(238)	(343)
Dividends Paid on Common Stock	(5,000)	(2,500)
Net Cash Flows Used For Financing Activities	(15,105)	(8,883)
Net Increase (Decrease) in Cash and Cash Equivalents	73	(103)
Cash and Cash Equivalents at Beginning of Period	702	526
Cash and Cash Equivalents at End of Period	$ 775	$ 423
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 5,371	$ 4,156
Net Cash Paid for Income Taxes	738	214
Noncash Acquisitions Under Capital Leases	139	224
Construction Expenditures Included in Accounts Payable at March 31,	2,257	3,079

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to KPCo'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 KPCo.

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 95
Changes in Gross Margin:		
Retail Margins	59	
Off-system Sales	(22)	
Transmission Revenues	(9)	
Other	(10)	
Total Change in Gross Margin		18
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(28)	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	(1)	
Interest Expense	(3)	
Total Change in Operating Expenses and Other		(37)
Income Tax Expense		3
First Quarter of 2007		$ 79

Net Income decreased $16 million to $79 million in 2007. The key driver of the decrease was a $37 million increase in Operating Expenses and Other offset by an $18 million increase in Gross Margin.

The major components of our 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 $59 million primarily due to the following:
  - A $25 million increase in capacity settlements under the Interconnection Agreement related to certain of our affiliates' peaks and the expiration of our supplemental capacity and energy obligation to Buckeye Power, Inc. under the Cardinal Station Agreement.
  - A $14 million increase in rate revenues related to an $8 million increase in our RSP, a $3 million increase related to rate recovery of storm costs and a $3 million increase related to rate recovery of IGCC preconstruction costs (see "Ohio Rate Matters" section of Note 3). The increase in rate recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction costs was offset by the amortization of deferred expenses in

Depreciation and Amortization.

- A $9 million increase in fuel margins.
- A $7 million increase in industrial revenue due to the addition of Ormet, a major industrial customer (see “Ormet” section of Note 3).
- A $6 million increase in residential revenue primarily due to a 25% increase in heating degree days.

These increases were partially offset by:

- A $9 million decrease in revenues associated with SO_2 allowances received in 2006 from Buckeye Power, Inc. under the Cardinal Station Allowances Agreement.

- Margins from Off-system Sales decreased $22 million due to a $19 million decrease in physical sales margins and a $4 million decrease in margins from optimization activities.
- Transmission Revenues decreased $9 million primarily due to the elimination of SECA revenues as of April 1, 2006 (see the “Transmission Rate Proceedings at the FERC” section of Note 3).
- Other revenues decreased $10 million primarily due to a $4 million decrease related to the expiration of an obligation to sell supplemental capacity and energy to Buckeye Power, Inc. under the Cardinal Station Agreement, a $3 million decrease in gains on sales of emission allowances and a $2 million decrease in revenue associated with Cook Coal Terminal.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $28 million primarily due to a $19 million increase in maintenance and removal costs related to planned and forced outages at the Gavin, Muskingum, Mitchell and Cardinal plants and a $5 million increase due to the prior period adjustment of liabilities related to sold coal companies.
- Depreciation and Amortization increased $5 million primarily due to the amortization of IGCC preconstruction costs of $3 million in the first quarter of 2007 and a $1 million increase in depreciation related to environmental improvements placed in service at the Mitchell plant. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins.
- Interest Expense increased $3 million primarily due to a $5 million increase related to long-term debt issuances since June 2006 and a $3 million increase related to higher borrowings from the Utility Money Pool partially offset by a $6 million increase in allowance for borrowed funds used during construction.

Income Taxes

Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income offset in part by state income taxes.

<u>Financial Condition</u>

Credit Ratings

The rating agencies currently have us on stable outlook. 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, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,625	$ 1,240
Cash Flows From (Used For):		
Operating Activities	96,864	182,002
Investing Activities	(306,826)	(221,862)
Financing Activities	209,598	39,577
Net Decrease in Cash and Cash Equivalents	(364)	(283)
Cash and Cash Equivalents at End of Period	$ 1,261	$ 957

Operating Activities

Net Cash Flows From Operating Activities were $97 million in 2007. We produced Net 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 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. Accounts Payable had a $26 million outflow primarily due to emission allowance payments in January 2007. Fuel, Materials and Supplies had a $24 million outflow primarily due to an increase in coal inventories.

Our Net Cash Flows From Operating Activities were $182 million in 2006. We produced income of $95 million during the period and a noncash expense item of $79 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 two items. Accounts Receivable, Net had a $102 million inflow due to receivables collected from our affiliates related to power sales, settled litigation and emission allowances. Accounts Payable had a $60 million outflow due to emission allowance payments in January 2006 and temporary timing differences for payments to affiliates.

Investing Activities

Our Net Cash Used For Investing Activities were $307 million and $222 million in 2007 and 2006, respectively. Construction Expenditures were $302 million and $223 million in 2007 and 2006, 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 2007, we expect construction expenditures to be approximately $530 million.

Financing Activities

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.

Net Cash Flows From Financing Activities were $40 million in 2006 primarily due to a $35 million capital contribution from AEP.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2007 were:

Issuances

None

Retirements

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Notes Payable - Nonaffiliated	$	1,463	6.81	2008
Notes Payable - Nonaffiliated		6,000	6.27	2009

In April 2007, we issued $400 million of three-year floating rate notes at an initial rate of 5.53% due in 2010. The proceeds from this issuance will contribute to our investment in environmental equipment.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2006 Annual Report and has not changed significantly from year-end other than the debt issuance discussed in "Financing Activity" above.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome 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 our pending litigation and regulatory proceedings, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in our 2006 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". Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management assets and liabilities are managed by AEPSC as agent for us. 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 us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of March 31, 2007 and the reasons for changes in our total MTM value as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of March 31, 2007 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 49,092	$ 756	$ -	$ 49,848
Noncurrent Assets	57,316	96	-	57,412
Total MTM Derivative Contract Assets	106,408	852	-	107,260
Current Liabilities	(42,532)	(3,980)	(2,071)	(48,583)
Noncurrent Liabilities	(35,731)	(312)	(5,493)	(41,536)
Total MTM Derivative Contract Liabilities	(78,263)	(4,292)	(7,564)	(90,119)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 28,145	$ (3,440)	$ (7,564)	$ 17,141

(a) See "Natural Gas Contracts with DETM" section of Note 16 in the 2006 Annual Report.

MTM Risk Management Contract Net Assets Three Months Ended March 31, 2007 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 33,042
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(4,433)
Fair Value of New Contracts at Inception When Entered During the Period (a)	311
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(23)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(317)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(435)
Total MTM Risk Management Contract Net Assets	28,145

Net Cash Flow Hedge Contracts		(3,440)
DETM Assignment (d)		(7,564)
Total MTM Risk Management Contract Net Assets at March 31, 2007	$	17,141

(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) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 16 in our 2006 Annual Report.

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

The following table presents:

· The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
· 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
Fair Value of Contracts as of March 31, 2007
(in thousands)

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted - Exchange Traded Contracts	$ 11,122	$ (399)	$ 464	$ -	$ -	$ -	$ 11,187
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(621)	9,668	7,524	2,985	-	-	19,556
Prices Based on Models and Other Valuation Methods (b)	(5,725)	(3,527)	1,165	3,608	812	1,069	(2,598)
Total	$ 4,776	$ 5,742	$ 9,153	$ 6,593	$ 812	$ 1,069	$ 28,145

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified

as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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

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 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 anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We use forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. 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 the changes from December 31, 2006 to March 31, 2007. 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, 2007
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2006	$ 4,040	$ (331)	$ 3,553	$ 7,262
Changes in Fair Value	(4,677)	-	-	(4,677)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(1,595)	3	(202)	(1,794)
Ending Balance in AOCI March 31, 2007	$ (2,232)	$ (328)	$ 3,351	$ 791

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,292 thousand loss.

Credit Risk

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

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, 2007, 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:

Three Months Ended March 31, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$678	$2,054	$924	$255	$573	$1,451	$500	$271

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $131 million and $110 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
REVENUES		
Electric Generation, Transmission and Distribution	$ 492,534	$ 544,639
Sales to AEP Affiliates	178,894	149,259
Other - Affiliated	4,038	3,709
Other - Nonaffiliated	3,975	4,999
TOTAL	679,441	702,606
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	198,293	235,130
Purchased Electricity for Resale	24,854	21,714
Purchased Electricity from AEP Affiliates	20,966	28,572
Other Operation	102,987	86,629
Maintenance	59,148	47,524
Depreciation and Amortization	84,276	78,821
Taxes Other Than Income Taxes	48,385	47,153
TOTAL	538,909	545,543
OPERATING INCOME	140,532	157,063
Other Income (Expense):		
Interest Income	412	637
Carrying Costs Income	3,541	3,383
Allowance for Equity Funds Used During Construction	571	738
Interest Expense	(25,931)	(23,414)
INCOME BEFORE INCOME TAXES	119,125	138,407
Income Tax Expense	39,864	43,375
NET INCOME	79,261	95,032
Preferred Stock Dividend Requirements	183	183
EARNINGS APPLICABLE TO COMMON STOCK	$ 79,078	$ 94,849

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 321,201	$ 466,637	$ 979,354	$ 755	$ 1,767,947
Capital Contribution From Parent		35,000			35,000
Preferred Stock Dividends			(183)		(183)
TOTAL					1,802,764
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,326				6,176	6,176
NET INCOME			95,032		95,032
TOTAL COMPREHENSIVE INCOME					101,208
MARCH 31, 2006	$ 321,201	$ 501,637	$ 1,074,203	$ 6,931	$ 1,903,972
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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,261	$ 1,625
Accounts Receivable:		
Customers	114,608	86,116
Affiliated Companies	109,029	108,214
Accrued Unbilled Revenues	17,082	10,106
Miscellaneous	3,620	1,819
Allowance for Uncollectible Accounts	(838)	(824)
Total Accounts Receivable	243,501	205,431
Fuel	139,950	120,441
Materials and Supplies	78,866	74,840
Emission Allowances	12,302	10,388
Risk Management Assets	49,848	86,947
Accrued Tax Benefits	3,181	22,909
Prepayments and Other	28,395	18,416
TOTAL	557,304	540,997
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,747,459	4,413,340
Transmission	1,038,642	1,030,934
Distribution	1,336,874	1,322,103
Other	300,054	299,637
Construction Work in Progress	1,226,985	1,339,631
Total	8,650,014	8,405,645
Accumulated Depreciation and Amortization	2,867,416	2,836,584
TOTAL - NET	5,782,598	5,569,061
OTHER NONCURRENT ASSETS		
Regulatory Assets	387,201	414,180
Long-term Risk Management Assets	57,412	70,092
Deferred Charges and Other	209,873	224,403
TOTAL	654,486	708,675
TOTAL ASSETS	$ 6,994,388	$ 6,818,733

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 397,127	$ 181,281
Accounts Payable:		
General	225,809	250,025
Affiliated Companies	116,297	145,197
Short-term Debt - Nonaffiliated	4,503	1,203
Long-term Debt Due Within One Year - Nonaffiliated	17,854	17,854
Risk Management Liabilities	48,583	73,386
Customer Deposits	31,547	31,465
Accrued Taxes	148,057	165,338
Accrued Interest	34,561	35,497
Other	126,845	123,631
TOTAL	1,151,183	1,024,877
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	2,176,601	2,183,887
Long-term Debt - Affiliated	200,000	200,000
Long-term Risk Management Liabilities	41,536	52,929
Deferred Income Taxes	891,761	911,221
Regulatory Liabilities and Deferred Investment Tax Credits	173,946	185,895
Deferred Credits and Other	249,254	219,127
TOTAL	3,733,098	3,753,059
TOTAL LIABILITIES	4,884,281	4,777,936
Minority Interest	17,910	15,825
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,628	16,630
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	536,639	536,639
Retained Earnings	1,280,963	1,207,265
Accumulated Other Comprehensive Income (Loss)	(63,234)	(56,763)
TOTAL	2,075,569	2,008,342
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,994,388	$ 6,818,733

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 79,261	$ 95,032
Adjustments for Noncash Items:		
Depreciation and Amortization	84,276	78,821
Deferred Income Taxes	2,851	3,604
Carrying Costs Income	(3,541)	(3,383)
Mark-to-Market of Risk Management Contracts	3,958	(3,616)
Deferred Property Taxes	17,920	17,331
Change in Other Noncurrent Assets	(4,406)	2,455
Change in Other Noncurrent Liabilities	(4,434)	13,855
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(38,070)	101,866
Fuel, Materials and Supplies	(23,535)	(18,238)
Accounts Payable	(25,807)	(60,411)
Customer Deposits	82	(12,497)
Accrued Taxes, Net	6,360	3,116
Accrued Interest	(2,986)	(10,998)
Other Current Assets	1,706	(739)
Other Current Liabilities	3,229	(24,196)
Net Cash Flows From Operating Activities	96,864	182,002
INVESTING ACTIVITIES		
Construction Expenditures	(301,635)	(222,600)
Change in Other Cash Deposits, Net	(7,988)	(1,651)
Proceeds from Sale of Assets	2,797	2,389
Net Cash Flows Used For Investing Activities	(306,826)	(221,862)
FINANCING ACTIVITIES		
Capital Contributions from Parent Company	-	35,000
Change in Short-term Debt, Net - Nonaffiliated	3,300	636
Change in Advances from Affiliates, Net	215,846	10,972
Retirement of Long-term Debt - Nonaffiliated	(7,463)	(4,713)
Principal Payments for Capital Lease Obligations	(1,902)	(2,135)
Dividends Paid on Cumulative Preferred Stock	(183)	(183)
Net Cash Flows From Financing Activities	209,598	39,577
Net Decrease in Cash and Cash Equivalents	(364)	(283)
Cash and Cash Equivalents at Beginning of Period	1,625	1,240
Cash and Cash Equivalents at End of Period	$ 1,261	$ 957
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 29,646	$ 29,152
Net Cash Paid (Received) for Income Taxes	(8,899)	922
Noncash Acquisitions Under Capital Leases	608	927

Construction Expenditures Included in Accounts Payable at March 31,	98,653	82,024

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Loss
(in millions)

First Quarter of 2006		$	(5)
Changes in Gross Margin:			
Retail and Off-system Sales Margins	5		
Transmission Revenues	1		
Other	(1)		
Total Change in Gross Margin			5
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(27)		
Depreciation and Amortization	(2)		
Interest Expense	(2)		
Total Change in Operating Expenses and Other			(31)
Income Tax Credit			11
First Quarter of 2007		$	(20)

Net Loss increased $15 million to $20 million in 2007. The key driver of the increased loss was a $31 million increase in Operating Expenses and Other, partially offset by an $11 million increase in Income Tax Credit and a $5 million increase in Gross Margin.

The major component of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power was a $5 million increase in Retail and Off-system Sales Margins primarily due to a $4 million increase in retail margins resulting from an increase in heating degree days.

Operating Expenses and Other increased between years as follows:

- Other Operation and Maintenance expenses increased $27 million due to:
  - A $21 million increase in distribution maintenance expense primarily due to a January 2007 ice storm.
  - A $2 million increase in administrative and general expenses, mostly due to increased employee-related expenses.
- Interest Expense increased $2 million primarily due to increased borrowings.

Income Taxes

Income Tax Credit increased $11 million primarily due to an increase in pretax book loss and a decrease in state income taxes.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in our 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $42 million and $39 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
REVENUES		
Electric Generation, Transmission and Distribution	$ 290,080	$ 339,601
Sales to AEP Affiliates	24,593	14,068
Other	640	1,060
TOTAL	315,313	354,729
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	142,515	213,173
Purchased Electricity for Resale	67,409	33,217
Purchased Electricity from AEP Affiliates	13,484	21,231
Other Operation	41,007	36,756
Maintenance	43,085	20,307
Depreciation and Amortization	22,706	21,132
Taxes Other Than Income Taxes	10,294	10,076
TOTAL	340,500	355,892
OPERATING LOSS	(25,187)	(1,163)
Other Income (Expense):		
Interest Income	646	569
Interest Expense	(11,383)	(9,135)
LOSS BEFORE INCOME TAXES	(35,924)	(9,729)
Income Tax Credit	(15,498)	(4,372)
NET LOSS	(20,426)	(5,357)
Preferred Stock Dividend Requirements	53	53
LOSS APPLICABLE TO COMMON STOCK	$ (20,479)	$ (5,410)

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 157,230	$ 230,016	$ 162,615	$ (1,264)	$ 548,597
Preferred Stock Dividends			(53)		(53)
TOTAL					548,544
COMPREHENSIVE LOSS					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $749				1,391	1,391
NET LOSS			(5,357)		(5,357)
TOTAL COMPREHENSIVE LOSS					(3,966)
MARCH 31, 2006	$ 157,230	$ 230,016	$ 157,205	$ 127	$ 544,578
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 Company		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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,584	$ 1,651
Accounts Receivable:		
Customers	51,680	70,319
Affiliated Companies	73,191	73,318
Miscellaneous	13,004	10,270
Allowance for Uncollectible Accounts	(89)	(5)
Total Accounts Receivable	137,786	153,902
Fuel	19,028	20,082
Materials and Supplies	52,951	48,375
Risk Management Assets	56,139	100,802
Accrued Tax Benefits	25,206	4,679
Regulatory Asset for Under-Recovered Fuel Costs	-	7,557
Margin Deposits	22,705	35,270
Prepayments and Other	5,718	5,732
TOTAL	321,117	378,050
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,095,466	1,091,910
Transmission	505,326	503,638
Distribution	1,248,077	1,215,236
Other	237,383	234,227
Construction Work in Progress	158,637	141,283
Total	3,244,889	3,186,294
Accumulated Depreciation and Amortization	1,200,212	1,187,107
TOTAL - NET	2,044,677	1,999,187
OTHER NONCURRENT ASSETS		
Regulatory Assets	138,815	142,905
Long-term Risk Management Assets	13,748	17,066
Employee Benefits and Pension Assets	29,761	30,161
Deferred Charges and Other	34,237	11,677
TOTAL	216,561	201,809
TOTAL ASSETS	$ 2,582,355	$ 2,579,046

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 135,694	$ 76,323
Accounts Payable:		
General	173,021	165,618
Affiliated Companies	68,782	65,134
Risk Management Liabilities	46,530	88,469
Customer Deposits	41,404	51,335
Accrued Taxes	35,144	19,984
Regulatory Liability for Over-Recovered Fuel Costs	9,015	-
Other	29,898	58,651
TOTAL	539,488	525,514
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	670,042	669,998
Long-term Risk Management Liabilities	8,514	11,448
Deferred Income Taxes	407,365	414,197
Regulatory Liabilities and Deferred Investment Tax Credits	306,194	315,584
Deferred Credits and Other	60,872	51,605
TOTAL	1,452,987	1,462,832
TOTAL LIABILITIES	1,992,475	1,988,346
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	250,016	230,016
Retained Earnings	178,397	199,262
Accumulated Other Comprehensive Income (Loss)	(1,025)	(1,070)
TOTAL	584,618	585,438
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,582,355	$ 2,579,046

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

		2007		2006
OPERATING ACTIVITIES				
Net Loss	$	(20,426)	$	(5,357)
Adjustments for Noncash Items:				
Depreciation and Amortization		22,706		21,132
Deferred Income Taxes		1,039		(23,436)
Mark-to-Market of Risk Management Contracts		3,108		9,106
Deferred Property Taxes		(24,809)		(24,295)
Change in Other Noncurrent Assets		4,393		11,118
Change in Other Noncurrent Liabilities		(11,269)		(20,806)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net		16,116		33,852
Fuel, Materials and Supplies		(3,513)		(26)
Margin Deposits		12,565		5,065
Accounts Payable		6,941		(77,217)
Customer Deposits		(9,931)		(13,056)
Accrued Taxes, Net		(4,378)		34,196
Fuel Over/Under Recovery, Net		16,572		74,281
Other Current Assets		(139)		1,021
Other Current Liabilities		(26,677)		(23,048)
Net Cash Flows From (Used for) Operating Activities		(17,702)		2,530
INVESTING ACTIVITIES				
Construction Expenditures		(61,301)		(45,539)
Change in Other Cash Deposits, Net		(29)		6
Proceeds from Sales of Assets		17		-
Net Cash Flows Used For Investing Activities		(61,313)		(45,533)
FINANCING ACTIVITIES				
Capital Contributions from Parent Company		20,000		-
Change in Advances from Affiliates, Net		59,371		42,932
Principal Payments for Capital Lease Obligations		(370)		(206)
Dividends Paid on Cumulative Preferred Stock		(53)		(53)
Net Cash Flows From Financing Activities		78,948		42,673
Net Decrease in Cash and Cash Equivalents		(67)		(330)
Cash and Cash Equivalents at Beginning of Period		1,651		1,520
Cash and Cash Equivalents at End of Period	$	1,584	$	1,190
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	12,921	$	8,681
Net Cash Paid for Income Taxes		2,623		575
Noncash Acquisitions Under Capital Leases		283		564
Construction Expenditures Included in Accounts Payable at March 31,		19,038		6,052

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2007 Compared to First Quarter of 2006

Reconciliation of First Quarter of 2006 to First Quarter of 2007
Net Income
(in millions)

First Quarter of 2006		$ 18
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	(1)	
Other	(4)	
Total Change in Gross Margin		(5)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(6)	
Depreciation and Amortization	(1)	
Other Income	1	
Interest Expense	(3)	
Total Change in Operating Expenses and Other		(9)
Income Tax Expense		6
First Quarter of 2007		$ 10

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

Net Income decreased $8 million to $10 million in 2007. The key drivers of the decrease were a $9 million increase in Operating Expenses and Other and a $5 million decrease in Gross Margin, offset by a $6 million decrease in Income Tax Expense.

The major component of our decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power was a $4 million decrease in Other changes in gross margin, primarily due to lower gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $6 million primarily due to a $2 million increase in generation operation and maintenance, a $1 million increase in transmission expenses due to higher SPP administration fees and a $1 million increase in administrative and general expenses, primarily associated with outside services and employee-related expenses.
- Interest Expense increased $3 million primarily due to increased long-term debt.

Income Taxes

Income Tax Expense decreased $6 million primarily due to a decrease in pretax book income and state income taxes.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

Cash Flow

Cash flows for the three months ended March 31, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,618	$ 3,049
Cash Flows From (Used For):		
Operating Activities	65,590	41,293
Investing Activities	(120,639)	(54,294)
Financing Activities	54,331	12,501
Net Decrease in Cash and Cash Equivalents	(718)	(500)
Cash and Cash Equivalents at End of Period	$ 1,900	$ 2,549

Operating Activities

Net Cash Flows From Operating Activities were $66 million in 2007. We produced Net Income of $10 million during the period and 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 $22 million inflow from Margin Deposits was due to decreased trading-related deposits resulting from normal trading activities. The $20 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company.

Our Net Cash Flows From Operating Activities were $41 million in 2006. We produced Net Income of $18 million during the period and noncash expense items of $33 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. The $27 million inflow from Accounts Receivable, Net was due to lower affiliated energy transactions. The $18 million outflow from Fuel, Materials and Supplies was the result of reduced fuel consumption during scheduled power plant outages. The $45 million inflow from Accrued Taxes, Net was due to increased income taxes. We did not make a federal income tax payment in 2006. The $16 million outflow from Customer Deposits was due to lower trading-related deposits. In addition, our cash flow related to Over/Under Fuel Recovery was favorably impacted by the new fuel surcharges effective December 2005 in our Arkansas service territory and in January 2006 in our Texas service territory. The $15 million outflow from

Accounts Payable was the result of lower expenditures related to tree trimming and right-of-way clearing, energy purchases and general operations.

Investing Activities

Cash Flows Used For Investing Activities during 2007 and 2006 were $121 million and $54 million, respectively. The $108 million of cash flows for Construction Expenditures during 2007 were primarily related to new generation facilities. In addition, we had a net increase of $9 million in loans to the Utility Money Pool. The cash flows during 2006 were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability.

Financing Activities

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

Cash Flows From Financing Activities were $13 million during 2006. We had a net increase of $21 million in borrowings from the Utility Money Pool. We paid $10 million in common stock dividends.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2007 were:

Issuances

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	250,000	5.55	2017

Retirements

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Notes Payable - Nonaffiliated	$	1,645	4.47	2011
Notes Payable - Nonaffiliated		4,000	6.36	2007
Notes Payable - Nonaffiliated		750	Variable	2008

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2006 Annual Report and has not changed significantly since year-end other than the debt issuance discussed in "Financing Activity" above and Energy and Capacity Purchase Contracts. Effective January 1, 2007, we transferred a significant amount of ERCOT energy marketing contracts to AEPEP; thereby decreasing our future obligations in Energy and Capacity Purchase Contracts. See "ERCOT Contracts Transferred to AEPEP" section of Note 1.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome 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 our pending litigation and regulatory proceedings, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in our 2006 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. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

New Generation

In December 2005, we sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, we announced plans to construct new generation to satisfy the demands of its customers. We will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and will build a 480 MW combined-cycle natural gas fired plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana. We also plan to build a new 600 MW base load coal plant, of which our investment will be 73%, in Hempstead County, Arkansas by 2011 to meet the long-term generation needs of its customers. Preliminary cost estimates our share of the new facilities are approximately $1.4 billion (this total excludes the related transmission investment and AFUDC). These new facilities are subject to regulatory approvals from our three state commissions. The peaking generation facility in Tontitown, Arkansas has been approved by all three state commissions and Units 3 and 4 are projected to be online in July 2007 and the remaining two units by 2008. Construction is expected to begin in 2007 on the intermediate and base load facilities upon approval from the state regulatory commissions. Expenditures related to construction of these facilities are expected to total $349 million in 2007.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 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 for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management assets and liabilities are managed by AEPSC as agent for us. 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 us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of March 31, 2007 and the reasons for changes in our total MTM value as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of March 31, 2007 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 66,352	$ 582	$ 66,934
Noncurrent Assets	16,264	37	16,301
Total MTM Derivative Contract Assets	82,616	619	83,235
Current Liabilities	(55,257)	(6)	(55,263)
Noncurrent Liabilities	(10,158)	(16)	(10,174)
Total MTM Derivative Contract Liabilities	(65,415)	(22)	(65,437)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 17,201	$ 597	$ 17,798

MTM Risk Management Contract Net Assets Three Months Ended March 31, 2007 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 20,166
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(1,013)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	21
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(1,973)
Total MTM Risk Management Contract Net Assets	17,201
Net Cash Flow Hedge Contracts	597
Total MTM Risk Management Contract Net Assets at March 31, 2007	$ 17,798

(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) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- 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
Fair Value of Contracts as of March 31, 2007
(in thousands)

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted - Exchange Traded Contracts	$ (16,029)	$ 1,742	$ (283)	$ -	$ -	$ -	$ (14,570)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	29,194	4,143	(813)	-	-	-	32,524
Prices Based on Models and Other Valuation Methods (b)	(2,551)	335	1,461	2	-	-	(753)
Total	$ 10,614	$ 6,220	$ 365	$ 2	$ -	$ -	$ 17,201

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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

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 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 anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We use forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. 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 the changes from December 31, 2006 to March 31, 2007. 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, 2007
(in thousands)

	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2006	$ (6,435)	$ 25	$ (6,410)
Changes in Fair Value	(1,019)	509	(510)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	183	-	183
Ending Balance in AOCI March 31, 2007	$ (7,271)	$ 534	$ (6,737)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $249 thousand loss.

Credit Risk

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

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, 2007, 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:

Three Months Ended March 31, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$83	$245	$100	$25	$447	$2,171	$794	$68

The High VaR for the twelve months ended December 31, 2006 occurred in the fourth quarter due to volatility in the ERCOT region.

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $43 million and $25 million at March 31, 2007 and December 31, 2006, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
REVENUES		
Electric Generation, Transmission and Distribution	$ 327,284	$ 293,993
Sales to AEP Affiliates	16,415	10,765
Other	400	374
TOTAL	344,099	305,132
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	111,987	90,661
Purchased Electricity for Resale	52,498	29,218
Purchased Electricity from AEP Affiliates	22,917	23,337
Other Operation	53,783	49,700
Maintenance	26,339	24,657
Depreciation and Amortization	34,122	32,617
Taxes Other Than Income Taxes	15,991	15,982
TOTAL	317,637	266,172
OPERATING INCOME	26,462	38,960
Other Income (Expense):		
Interest Income	705	543
Allowance for Equity Funds Used During Construction	1,391	185
Interest Expense	(15,490)	(12,771)
INCOME BEFORE INCOME TAXES AND MINORITY INTEREST EXPENSE	13,068	26,917
Income Tax Expense	2,621	8,823
Minority Interest Expense	842	222
NET INCOME	9,605	17,872
Preferred Stock Dividend Requirements	57	57
EARNINGS APPLICABLE TO COMMON STOCK	$ 9,548	$ 17,815

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 135,660	$ 245,003	$ 407,844	$ (6,129)	$ 782,378
Common Stock Dividends			(10,000)		(10,000)
Preferred Stock Dividends			(57)		(57)
TOTAL					772,321
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $930				1,728	1,728
NET INCOME			17,872		17,872
TOTAL COMPREHENSIVE INCOME					19,600
MARCH 31, 2006	$ 135,660	$ 245,003	$ 415,659	$ (4,401)	$ 791,921
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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2007 and December 31, 2006
(in thousands)
(Unaudited)

		2007		2006
CURRENT ASSETS				
Cash and Cash Equivalents	$	1,900	$	2,618
Advances to Affiliates		8,959		-
Accounts Receivable:				
Customers		74,382		88,245
Affiliated Companies		48,598		59,679
Miscellaneous		13,077		8,595
Allowance for Uncollectible Accounts		(137)		(130)
Total Accounts Receivable		135,920		156,389
Fuel		73,479		69,426
Materials and Supplies		46,101		46,001
Risk Management Assets		66,934		120,036
Margin Deposits		19,353		41,579
Prepayments and Other		28,581		18,256
TOTAL		381,227		454,305
PROPERTY, PLANT AND EQUIPMENT				
Electric:				
Production		1,586,238		1,576,200
Transmission		690,384		668,008
Distribution		1,262,203		1,228,948
Other		611,255		595,429
Construction Work in Progress		301,251		259,662
Total		4,451,331		4,328,247
Accumulated Depreciation and Amortization		1,868,974		1,834,145
TOTAL - NET		2,582,357		2,494,102
OTHER NONCURRENT ASSETS				
Regulatory Assets		153,080		156,420
Long-term Risk Management Assets		16,301		20,531
Employee Benefits and Pension Assets		25,302		26,029
Deferred Charges and Other		68,855		39,581
TOTAL		263,538		242,561
TOTAL ASSETS	$	3,227,122	$	3,190,968

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 188,965
Accounts Payable:		
General	155,206	140,424
Affiliated Companies	72,448	68,680
Short-term Debt - Nonaffiliated	20,433	17,143
Long-term Debt Due Within One Year - Nonaffiliated	97,768	102,312
Risk Management Liabilities	55,263	109,578
Customer Deposits	36,798	48,277
Accrued Taxes	64,418	31,591
Regulatory Liability for Over-Recovered Fuel Costs	33,791	26,012
Other	66,871	85,086
TOTAL	602,996	818,068
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	822,519	576,694
Long-term Debt - Affiliated	50,000	50,000
Long-term Risk Management Liabilities	10,174	14,083
Deferred Income Taxes	362,321	374,548
Regulatory Liabilities and Deferred Investment Tax Credits	347,951	346,774
Deferred Credits and Other	196,064	183,087
TOTAL	1,789,029	1,545,186
TOTAL LIABILITIES	2,392,025	2,363,254
Minority Interest	1,619	1,815
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	245,003	245,003
Retained Earnings	467,244	459,338
Accumulated Other Comprehensive Income (Loss)	(19,126)	(18,799)
TOTAL	828,781	821,202
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,227,122	$ 3,190,968

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 9,605	$ 17,872
Adjustments for Noncash Items:		
Depreciation and Amortization	34,122	32,617
Deferred Income Taxes	(6,677)	(9,101)
Mark-to-Market of Risk Management Contracts	2,965	10,468
Deferred Property Taxes	(28,815)	(28,997)
Change in Other Noncurrent Assets	(3,198)	9,458
Change in Other Noncurrent Liabilities	(178)	(19,121)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	20,469	26,848
Fuel, Materials and Supplies	(4,141)	(17,521)
Margin Deposits	22,226	7,915
Accounts Payable	13,806	(15,304)
Customer Deposits	(11,479)	(15,861)
Accrued Taxes, Net	36,113	45,238
Fuel Over/Under Recovery, Net	4,212	15,216
Other Current Assets	(2,868)	2,821
Other Current Liabilities	(20,572)	(21,255)
Net Cash Flows From Operating Activities	65,590	41,293
INVESTING ACTIVITIES		
Construction Expenditures	(107,613)	(54,238)
Change in Advances to Affiliates, Net	(8,959)	-
Other	(4,067)	(56)
Net Cash Flows Used For Investing Activities	(120,639)	(54,294)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	247,548	-
Change in Short-term Debt, Net - Nonaffiliated	3,290	4,394
Change in Advances from Affiliates, Net	(188,965)	20,988
Retirement of Long-term Debt - Nonaffiliated	(6,395)	(2,457)
Principal Payments for Capital Lease Obligations	(1,090)	(367)
Dividends Paid on Common Stock	-	(10,000)
Dividends Paid on Cumulative Preferred Stock	(57)	(57)
Net Cash Flows From Financing Activities	54,331	12,501
Net Decrease in Cash and Cash Equivalents	(718)	(500)
Cash and Cash Equivalents at Beginning of Period	2,618	3,049
Cash and Cash Equivalents at End of Period	$ 1,900	$ 2,549
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 16,747	$ 11,892
Net Cash Paid for Income Taxes	580	1,282

Noncash Acquisitions Under Capital Leases	3,192	3,412
Construction Expenditures Included in Accounts Payable at March 31,	32,460	12,800

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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.

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	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
4.	Commitments, Guarantees and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
5.	Acquisitions, Dispositions and Assets Held for Sale	AEGCo, CSPCo, TCC
6.	Benefit Plans	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
7.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Income Taxes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with accounting principles generally accepted in the United States of America (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 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, 2007 are not necessarily indicative of results that may be expected for the year ending December 31, 2007. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2006 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2006 as filed with the SEC on February 28, 2007.

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for Registrant Subsidiaries as of March 31, 2007 and December 31, 2006 is shown in the following table.

Components	March 31, 2007	December 31, 2006
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (10,031)	$ (2,547)
CSPCo	(1,878)	3,398
I&M	(14,255)	(8,962)
KPCo	(490)	1,552
OPCo	791	7,262
PSO	(1,025)	(1,070)
SWEPCo	(6,737)	(6,410)
TNC	-	(702)
SFAS 158 Adoption:		
APCo	$ (52,244)	$ (52,244)
CSPCo	(25,386)	(25,386)
I&M	(6,089)	(6,089)
OPCo	(64,025)	(64,025)
SWEPCo	(12,389)	(12,389)
TNC	(9,457)	(9,457)

Related Party Transactions

Oklaunion PPA between TNC and AEP Energy Partners

On January 1, 2007, TNC began a 20-year Power Purchase & Sale Agreement (PPA) with an affiliate, AEP Energy Partners (AEPEP), whereby TNC agrees to sell AEPEP 100% of TNC's capacity and associated energy from its undivided interest (54.69%) in the Oklaunion plant. AEPEP is to pay TNC for the capacity and associated energy delivered to the delivery point, the sum of fuel, operation and maintenance, depreciation, capacity and all taxes other than federal income taxes applicable. A portion of the payment is fixed and is payable regardless of the level of output. There are no penalties if TNC fails to maintain a minimum availability level or exceeds a maximum heat rate level. The PPA was approved by the FERC on July 12, 2006.

TNC recorded revenue of $23.4 million from AEPEP in the first quarter of 2007, which is included in Sales to AEP Affiliates on its 2007 Condensed Consolidated Statement of Income.

ERCOT Contracts Transferred to AEPEP

Effective January 1, 2007, PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEPEP and entered into intercompany financial and physical purchase and sale agreements with AEPEP. This was done to lock in PSO and SWEPCo’s margins on ERCOT trading and marketing contracts and to transfer the future associated commodity price and credit risk to AEPEP. The contracts will mature over the next three years.

PSO and SWEPCo have historically presented third party ERCOT trading and marketing activity on a net basis in Revenues - Electric Generation, Transmission and Distribution. The applicable ERCOT third party trading and marketing contracts that were not transferred to AEPEP will remain until maturity on PSO and SWEPCo and will be presented on a net basis in Sales to AEP Affiliates on PSO’s and SWEPCo’s Statements of Income.

The following table indicates the sales to AEPEP and the amounts reclassified from third party to affiliate:

	For the Three Months Ended March 31, 2007		
Company	**Net Settlement With AEPEP**	**Third Party Amounts Reclassified to Affiliate**	**Net Amount included in Sales to AEP Affiliates**
		(in thousands)	
PSO	$ 43,150	$ (35,837)	$ 7,313
SWEPCo	46,876	(38,259)	8,617

The following table indicates the affiliated portion of risk management assets and liabilities reflected on PSO’s and SWEPCo’s balance sheets associated with these contracts:

	As of March 31, 2007	
	PSO	**SWEPCo**
Current	**(in thousands)**	
Risk Management Assets	$ -	$ -
Risk Management Liabilities	(8,282)	(9,758)
Noncurrent		
Long-term Risk Management Assets	$ 584	$ 688
Long-term Risk Management Liabilities	(2,097)	(2,471)

Texas Restructuring - SPP - Affecting TNC and SWEPCo

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo’s and approximately 3% of TNC’s businesses were in SPP. A petition was filed in May 2006 requesting approval to transfer Mutual Energy SWEPCO L.P.’s (a subsidiary of AEP

C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, the final regulatory approval was received for the transfers. The transfers were effective February 2007 and were recorded at net book value of $11.6 million. The Arkansas Public Service Commission's approval requires SWEPCo to amend its fuel recovery tariff so that Arkansas customers do not pay the incremental cost of serving the additional load.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These revisions had no impact on the Registrant Subsidiaries' previously reported results of operations or changes in shareholders' equity.

On their statements of income, the Registrant Subsidiaries reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. The following table shows the credits reclassified by the Registrant Subsidiaries in 2006:

Company		Three Months Ended March 31, 2006 (in thousands)
AEGCo	$	27
APCo		296
I&M		5,589

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or 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 2007 and standards issued but not implemented that we have determined relate to our operations.

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 being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption.

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. Management expects that the adoption of this standard will impact MTM valuations of certain contracts, but is unable to quantify the effect. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. The Registrant Subsidiaries will adopt SFAS 157 effective January 1, 2008.

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.

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. 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. In the event we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. The Registrant Subsidiaries will adopt SFAS 159 effective January 1, 2008.

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48"

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. The Registrant Subsidiaries adopted FIN 48 effective January 1, 2007. The impact of this interpretation was an unfavorable (favorable) adjustment to retained earnings as follows:

Company	**(in thousands)**	
AEGCo	$	(27)
APCo		2,685
CSPCo		3,022
I&M		(327)
KPCo		786
OPCo		5,380
PSO		386
SWEPCo		1,642
TCC		2,187
TNC		557

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by 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 business combinations, revenue recognition, liabilities and equity, derivatives disclosures, emission allowances, 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 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 2006 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 2007 and updates the 2006 Annual Report.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans - Affecting CSPCo and OPCo

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs. Pursuant to the RSPs, CSPCo and OPCo implemented these proposed increases effective with the beginning of the May 2007 billing cycle. These increases are subject to refund until the PUCO issues a final order in the matter. The hearing is scheduled to begin in late May 2007.

In March 2007, CSPCo filed an application under the 4% provision of the RSP to adjust the Power Acquisition Rider (PAR) which was authorized in 2005 by the PUCO in connection with CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio. The PAR is intended to recover the difference between CSPCo's tariffed generation service rates and the cost of power acquired to serve the former Monongahela Power load. The PAR was set for an initial 17-month period of January 2006 through May 2007. The filing would adjust the PAR for the nineteen month period of June 2007 through December 2008. The filing reflects a true up for estimated under-recoveries during the initial period, $8 million as of March 31, 2007, as well as the power acquisition costs for the upcoming nineteen-month period. If approved, CSPCo's revenues would increase by $22 million and $38 million for 2007 and 2008, respectively.

In March 2007, CSPCo and OPCo filed a settlement agreement at the PUCO resolving the Ohio Supreme Court's remand of the PUCO’s RSP order. The Supreme Court indicated concern with the absence of a competitive bid process as an alternative to the generation rates set by the RSP. In response, the settling parties agreed to have CSPCo and OPCo take bids for Renewable Energy Certificates (RECs). CSPCo and OPCo will give customers the option to pay a generation rate premium that would encourage the development of renewable energy sources by reimbursing CSPCo and OPCo for the cost of the RECs and the administrative costs of the program. This settlement agreement was supported by the Office of Consumers' Counsel, the Ohio Partners for Affordable Energy, the Ohio Energy Group and the PUCO staff. In May 2007, the PUCO adopted the settlement agreement in its entirety.

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the RSPs on December 31, 2008. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, as permitted by the current Ohio restructuring legislation, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009 when the RSP period ends.

Customer Choice Deferrals - Affecting CSPCo and OPCo

As provided in the restructuring settlement agreement approved by the PUCO in 2000, CSPCo and OPCo established 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 which changes distribution rates after December 31, 2007 for OPCo and December 31, 2008 for CSPCo. Pursuant to the RSPs, recovery of these amounts for OPCo was further deferred until the next base rate filing to change distribution rates after the end of the RSP period of December 31, 2008. Through March 31, 2007, CSPCo and OPCo incurred $50 million and $51 million, respectively, of such costs and established regulatory assets of $25 million each for such costs. CSPCo and OPCo have not recognized $5 million and $6 million, respectively, of equity carrying costs, which are recognizable when collected. Management believes that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates.

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 during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over no more than a twelve-month period effective July 1, 2006. Through March 31, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each recovered $9 million of those costs. CSPCo and OPCo will recover the remaining amounts through June 30, 2007. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all charges collected for pre-construction costs, associated with items that may be utilized in IGCC projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. Management believes that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase I cost-related recoveries.

Distribution Reliability Plan - Affecting CSPCo and OPCo

In January 2006, CSPCo and OPCo initiated a proceeding at the PUCO seeking a new distribution rate rider to fund enhanced distribution reliability programs. In the fourth quarter of 2006, as directed by the PUCO, CSPCo and OPCo filed a proposed enhanced reliability plan. The plan contemplated CSPCo and OPCo recovering approximately $28 million and $43 million, respectively, in additional distribution revenue during an eighteen month period beginning July 2007. In January 2007, the OCC filed testimony, which argued that CSPCo and OPCo should be required to improve distribution service reliability with funds from their existing rates.

In April 2007, CSPCo and OPCo filed a joint motion with the PUCO staff, the Ohio Consumers' Counsel, the Appalachian People's Action Coalition, the Ohio Partners for Affordable Energy and the Ohio Manufacturers Association to withdraw the proposed enhanced reliability plan.

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, under a PUCO encouraged settlement agreement. The settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH to be paid by Ormet for power and a PUCO approved market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is not sufficient, an increase in RSP generation rates under the additional 4% provision of the RSPs. The $43 per MWH price to be paid by Ormet for generation services is above the industrial RSP generation tariff but below current market prices. In December 2006, CSPCo and OPCo submitted a market price of $47.69 per MWH for 2007, which is pending PUCO approval. If the PUCO approves a lower market price, it could have an adverse effect on 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 margins, which could have an adverse effect on future results of operations and cash flows.

Texas Rate Matters

TCC TEXAS RESTRUCTURING - Affecting TCC

Texas District Court Appeal Proceedings

TCC recovered its net recoverable stranded generation costs through a securitization financing and is refunding its net other true-up items through a CTC rate rider credit under 2006 PUCT orders. TCC appealed the PUCT stranded costs true-up 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, 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 statute 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 it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it 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 cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See "TCC and TNC Deferred Fuel" and"TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections below.

Municipal customers and other intervenors also appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007, the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. The judge directed that these matters should be remanded to the PUCT to determine the specific impact on TCC's future true-up revenues.

In March 2007, the District Court judge reversed his earlier preliminary decision and concluded the sale of assets method to value TCC's nuclear plant was appropriate. The District Court judge did not reconsider his preliminary ruling that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. The District Court judge also determined the PUCT improperly reduced TCC's net stranded plant costs from the sale of its generating units through the commercial unreasonableness disallowance, which could have a materially favorable effect on TCC. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding. If the District Court's carrying cost rate remand ruling is ultimately upheld on appeal and remanded to the PUCT for reconsideration, the PUCT could either confirm the existing weighted average carrying cost (WACC) rate or redetermine a new rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition. TCC, the PUCT and intervenors appealed the District Court ruling to the Court of Appeals. Management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If TCC ultimately succeeds in its appeals, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

OTHER TEXAS RESTRUCTURING MATTERS

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes - Affecting TCC

In TCC's 2006 true-up and securitization orders, the PUCT reduced net regulatory assets and the amount to be securitized by $51 million related to the present value of ADITC and by $10 million related to EDFIT associated with TCC's generation assets for a total reduction of $61 million.

TCC filed a request for a private letter ruling with the IRS in June 2005 regarding the permissibility under the IRS rules and regulations of the ADITC and EDFIT reduction proposed by the PUCT. The IRS issued its private letter ruling in May 2006, which stated that the PUCT's flow-through to customers of the present value of the ADITC and EDFIT benefits would result in a normalization violation. To address the matter and avoid a normalization violation, the PUCT agreed to allow TCC to defer an amount of the CTC refund totaling $103 million ($61 million in present value of ADITC and EDFIT associated with TCC's generation assets plus $42 million of related carrying costs) pending resolution of the normalization issue. If it is ultimately determined that a refund to customers through the true-up process of the ADITC and EDFIT, discussed above, is not a normalization violation, then TCC will be required to refund the $103 million, plus additional carrying costs. However, if such refund of ADITC and EDFIT is ultimately determined to cause a normalization violation, TCC anticipates it will be permitted to retain the $61 million present value of ADITC and EDFIT plus carrying costs, favorably impacting future results of operations.

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $104 million as of March 31, 2007, 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 returned to ratepayers under a nonappealable order. Management intends to continue its efforts to avoid a normalization violation that would adversely affect future results of operations and cash flows.

TCC and TNC Deferred Fuel - Affecting TCC and TNC

The TCC deferred fuel over-recovery regulatory liability is a component of the other true-up items net regulatory liability refunded through the CTC rate rider credit. In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and establish their final deferred fuel balances. In its final fuel reconciliation orders, the PUCT ordered a reduction in TCC's and TNC's recoverable fuel costs for, among other things, the reallocation of additional AEP System off-system sales margins under a FERC-approved SIA. Both TCC and TNC appealed the PUCT's rulings regarding a number of issues in the fuel orders in state court and challenged the jurisdiction of the PUCT over the allocation of off-system sales margin allocations in the federal court. Intervenors also appealed the PUCT's rulings in state court.

In 2006, the Federal District Court issued orders precluding the PUCT from enforcing the off-system sales reallocation portion of its ruling in the final TNC and TCC fuel reconciliation proceedings. The Federal court ruled, in both cases, that the FERC, not the PUCT, has jurisdiction over the allocation. The PUCT appealed both Federal District Court decisions to the United States Court of Appeals. In TNC's case, the Court of Appeals affirmed the District Court's decision. The PUCT has indicated they will appeal this ruling to the United States Supreme Court.

TCC has filed a Motion for Summary Affirmance based on the outcome of the TNC appeal. For TCC, the PUCT has conceded the issue concerning the allocation of off-system sales margins to AEP West companies under the SIA as governed by the TNC case. However, the PUCT continues to challenge the allocation of those margins among AEP West companies under the CSW Operating Agreement. If the PUCT's appeals are ultimately unsuccessful, TCC and TNC could record income of $16 million and $8 million, respectively, related to the reversal of the previously recorded fuel over-recovery regulatory liabilities.

If the PUCT is unsuccessful in the federal court system, it or another interested party may file a complaint at the FERC to address the allocation issue. If a complaint at the FERC results in the PUCT's decisions being adopted by the FERC, there could be an adverse effect on results of operations and cash flows. An unfavorable FERC ruling may result in a retroactive reallocation of off-system sales margins from AEP East companies to AEP West companies under the then existing SIA allocation method. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts reallocated to the West companies from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits. Although management cannot predict the ultimate outcome of this federal litigation, management believes that its allocations were in accordance with the then existing FERC-approved SIA and that it should not have to allocate additional off-system sales margins to the West companies including TCC and TNC.

In January 2007, TCC began refunding as part of the CTC rate rider credit described above, $149 million of its $165 million over-recovered deferred fuel regulatory liability. The remaining $16 million refund related to the favorable Federal District Court order has been deferred pending the outcome of the federal court appeal and would be subject to refund only upon a successful appeal by the PUCT.

Excess Earnings - Affecting TCC

In 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. TCC refunded $55 million of excess earnings, including interest, of which $30 million went to the affiliated REP. In November 2005, the PUCT filed a petition for review with the Supreme Court of Texas seeking reversal of the Texas Court of Appeals' decision. The Supreme Court of Texas requested briefing, which has been provided, but it has not decided whether it will hear the case. If the Court of Appeals decision is upheld and the refund mechanism is found to be unlawful, the impact on TCC would then depend on: (a) how and if TCC is ordered by the PUCT to refund the excess earnings through the true-up process to ultimate customers and (b) whether TCC will be able to recover the amounts previously refunded to the REPs including the REP TCC sold to Centrica. Management is unable to predict the ultimate outcome of this litigation and its effect on future results of operations and cash flows.

OTHER TEXAS RATE MATTERS

TCC and TNC Energy Delivery Base Rate Filings - Affecting TCC and TNC

TCC and TNC each filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rates in Texas. TCC and TNC requested $81 million and $25 million in annual increases, respectively. Both requests include a return on common equity of 11.25% and the impact of the expiration of the CSW merger savings rate credits. In March 2007, various intervenors and the PUCT staff filed their recommendations. Though the recommendations varied, the range of recommended increase was $8 million to $30 million for TCC and $1 million to $14 million for TNC. The recommended return on common equity ranged from 9.00% to 9.75%. In April 2007, TCC and TNC filed rebuttal testimony reducing the requested annual increases to $70 million for TCC and $22 million for TNC including a reduced requested return on common equity of 10.75%. Hearings began in April 2007 and are scheduled to be concluded in May 2007. Management expects the new base wires rates to become effective, subject to refund, in the second quarter of 2007 with a decision from the PUCT expected in the third quarter of 2007.

Management is unable to predict the ultimate effect of this filing on future results of operations, cash flows and financial condition.

SWEPCo Fuel Reconciliation - Texas - Affecting SWEPCo

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations. SWEPCo sought, in the proceedings, to include under-recoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The intervenor recommendations ranged from a $10 million to $28 million reduction. In February 2007, the PUCT staff filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced by $10 million. SWEPCo does not agree with the intervenor's or staff's recommendations and filed rebuttal testimony in February 2007. Hearings have been held and briefs have been filed. Results of operations could be adversely affected by $28 million plus carrying costs if the PUCT adopts all of the intervenor and staff recommendations. Management is unable to predict the outcome of this proceeding or its effect on future results of operations and cash flows.

Virginia Rate Matters

Virginia Restructuring - Affecting APCo

In April 2004, Virginia enacted legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides APCo with specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the restructuring law, APCo defers incremental environmental generation costs and incremental transmission and distribution reliability costs for future recovery, to the extent such costs are not being recovered when incurred, and amortizes a portion of such deferrals commensurate with recovery.

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation/supply rates. The amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation/supply will return to a form of cost-based regulation. The legislation provides for, among other things, biennial rate reviews beginning in 2009, rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investment, (b) Demand Side Management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments, significant return on equity enhancements for large investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, the amendments allow utilities to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. APCo expects this new form of cost-based ratemaking should improve its annual return on equity and cash flow from operations when new ratemaking begins in 2009. However, with the return of cost-based regulation, APCo's generation business will again meet the criteria for application of regulatory accounting principles under SFAS 71. Results of operations and financial condition could be adversely affected when APCo is required to re-establish certain net regulatory liabilities applicable to its generation/supply business. The timing and earnings effect from such reapplication of SFAS 71 regulatory accounting for APCo's Virginia generation/supply business are uncertain at this time.

APCo Virginia Base Rate Case - Affecting APCo

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including the cost of its investment in environmental equipment and a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to the fuel factor where they can be trued-up to actual. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which is estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. The major components of the $225 million base rate request include $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million mainly due to projected net environmental plant additions through September 30, 2007 and $48 million for return on equity.

In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund. The $198 million base rate increase being collected, subject to refund, includes recovery of incremental environmental compliance and transmission and distribution system reliability (E&R) costs projected to be incurred during the rate year beginning October 2006. These incremental E&R costs can be deferred and recovered through the E&R surcharge mechanism if not recovered through this base rate request. In October 2006, the Virginia SCC staff filed its direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. APCo filed rebuttal testimony in November 2006. Hearings were held in December 2006.

In March 2007, the Hearing Examiner (HE) issued a report recommending a $76 million increase in APCo's base rates and $45 million credit to the fuel factor for off-system sales margins. The HE's recommendations include a return on equity of 10.1% which would reduce APCo's revenue requirement by approximately $23 million. The HE also recommended limiting forward looking ratemaking adjustments to June 30, 2006 as opposed to September 30, 2007, which would reduce APCo's revenue requirement by approximately $72 million, of which approximately $60 million relates to incremental E&R costs that can be deferred for future recovery through the E&R surcharge mechanism. The HE further proposed to share the off-system sales margins using the twelve months ended June 30, 2006 of $101 million with 50% reducing base rates, 45% reducing fuel rates and 5% retained by APCo to determine the revenue requirement. APCo's proposal did not reduce base rates for off-system sales margins, but reduced fuel rates approximately $27 million for off-system sales margins. APCo expects a final order to be issued during 2007.

APCo is providing for a possible refund of revenues collected subject to refund consistent with the HE recommendations. Management is unable to predict the ultimate effect of this filing on future results of operations, cash flows and financial condition.

West Virginia Rate Matters

APCo Expanded Net Energy Cost (ENEC) Filing - Affecting APCo

In April 2007, the WVPSC issued an order establishing an investigation and hearing of APCo's and WPCo's 2007 ENEC joint compliance filing. 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 and other energy/transmission items. In the March 2007 ENEC joint compliance filing, APCo filed for an increase of approximately $91 million including a $65 million increase in ENEC and a $26 million increase in construction surcharges to become effective July 1, 2007. A hearing on the joint compliance filing is scheduled for May 2007.

APCo IGCC - Affecting APCo

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating

Station in Mason County, WV. In January 2007, at APCo's request, the WVPSC issued an order delaying the Commission's deadline for issuing an order on the certificate to December 2007. Through March 31, 2007, APCo deferred pre-construction IGCC costs totaling $10 million. If the plant is not built and these costs are not recoverable, future results of operations and cash flows would be adversely affected.

Indiana Rate Matters

I&M Depreciation Study Filing - Affecting I&M

In February 2007, I&M filed a request with the IURC for approval of revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counsel that would provide direct benefits to I&M's customers if new depreciation rates are approved by the IURC. The direct benefits would include a $5 million credit to fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement is approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense on an Indiana jurisdictional basis of approximately $69 million reflecting an NRC-approved 20-year extension of the Cook Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition was not a request for a change in customers' electric service rates. As proposed, the book depreciation reduction would increase earnings but would not impact cash flows until rates are revised. The IURC held a public hearing in April 2007. I&M requested expeditious review and approval of its filing, but management cannot predict the outcome of the request or the timing of any approved depreciation reduction. If approved as filed, pretax earnings would increase by $64 million in 2007.

Kentucky Rate Matters

KPCo Environmental Surcharge Filing - Affecting KPCo

In July 2006, KPCo filed for approval of an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge. KPCo estimates the amended environmental compliance plan and revised tariff would increase revenues over 2006 levels by approximately $2 million in 2007 and $6 million in 2008 for a total of $8 million of additional revenue at current cost projections. In January 2007, the KPSC issued an order approving KPCo's proposed plan and surcharge. Future recovery is based upon actual environmental costs and is subject to periodic review and approval of those actual costs by the KPSC.

In November 2006, the Kentucky Attorney General and the Kentucky Industrial Utility Consumers (KIUC) filed an appeal with the Kentucky Court of Appeals of the Franklin Circuit Court's 2006 order upholding the KPSC's 2005 Environmental Surcharge order. In its order, the KPSC approved KPCo's recovery of its environmental costs at its Big Sandy Plant and its share of environmental costs incurred as a result of the AEP Power Pool capacity settlement. The KPSC has allowed KPCo to recover these FERC-approved allocated costs, via the environmental surcharge, since the KPSC's first environmental surcharge order in 1997. KPCo presently recovers $7 million a year in environmental surcharge revenues.

In March 2007, the KPSC issued an order, at the request of the Kentucky Attorney General, stating the environmental surcharge collections authorized in the January 2007 order that are associated with out-of-state generating facilities should be collected over the six months beginning March 2007, subject to refund, pending the outcome of the court of appeals process. At this time, management is unable to predict the outcome of this proceeding and its effect on KPCo's current environmental surcharge revenues or on the January 2007 KPSC order increasing KPCo's environmental rates.

Oklahoma Rate Matters

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

In 2002, PSO under-recovered $44 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with the proposed reallocation of off-system sales margins of $27 million to $37 million and with $9 million attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the $9 million of reallocated purchased power costs assigned to wholesale customers had been refunded, thus removing that issue from its recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. The United States District Court for the Western District of Texas issued orders in September 2005 regarding a TNC fuel proceeding and in August 2006 regarding a TCC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has sole jurisdiction over that allocation. The PUCT appealed the ruling. The United States Court of Appeals for the Fifth Circuit, issued a decision in December 2006 regarding the TNC fuel proceeding that affirmed the United States District Court ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals other than the staff's original recommendation that PSO be allowed to recover the $42 million over three years and will defend its right to recover its under-recovered fuel balance. Management believes that if the position taken by the federal courts in the Texas proceeding is applied to PSO's case, then the OCC should be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party could file a complaint at the FERC alleging the allocation of off-system sales margins to PSO is improper, which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. However, to date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies, but even if one were asserted, management believes that it would not prevail.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. The OCC staff filed testimony finding no disallowances in the test year data. The Attorney General of Oklahoma filed testimony stating that they could not determine if PSO's gas procurement activities were prudent, but did not include a recommended disallowance. However, an intervenor filed testimony in June 2006 proposing the disallowance of $22 million in fuel costs based on a historical review of potential hedging opportunities that he alleges existed during the year. A hearing was held in August 2006 and management expects a recommendation from the ALJ in 2007.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to the required biennial reviews. In compliance with an OCC order, PSO is required to file its testimony by June 15, 2007. This proceeding will cover the year 2005.

Management cannot predict the outcome of the pending fuel and purchased power reviews or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the unrecovered 2002 reallocation of such costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

PSO Rate Filing - Affecting PSO

In November 2006, PSO filed a request to increase base rates $50 million for Oklahoma jurisdictional customers with a proposed effective date in the second quarter of 2007. PSO sought a return on equity of 11.75%. PSO also proposed a formula rate plan that, if approved as filed, will permit PSO to defer any unrecovered costs as a result of a revenue deficiency that exceeds 50 basis points of the allowed return on equity for recovery within twelve months beginning six months after the test year. The formula would enable PSO to recover on a timely basis the cost of its new generation, transmission and distribution construction (including carrying costs during construction), provide the opportunity to achieve the approved return on equity and avoid recording a significant AFUDC that would have been recorded during the construction time period.

In March 2007, the OCC staff and various intervenors filed testimony. The recommendations were base rate reductions that ranged from $18 million to $52 million. The recommended returns on equity ranged from 9.25% to 10.09%. These recommendations included reductions in depreciation expense of approximately $25 million, which has no earnings impact. The OCC staff filed testimony supporting a formula rate plan, generally similar to the one proposed by PSO. In April 2007, PSO filed rebuttal testimony regarding various issues raised by the OCC Staff and the intervenors. As a result of rebuttal testimony, PSO reduced its base rate request by $2 million. Hearings commenced on May 1, 2007.

Management is unable to predict the outcome of these proceedings, however, if rates are not increased in an amount sufficient to recover expected unavoidable cost increases future results of operations, cash flows and possibly financial condition could be adversely affected.

PSO Lawton and Peaking Generation Settlement Agreement - Affecting PSO

On November 26, 2003, pursuant to an application by Lawton Cogeneration, L.L.C. (Lawton) seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs. The order did not address recovery by PSO of the resultant purchased power costs.

In December 2003, PSO filed an appeal of the OCC’s order with the Oklahoma Supreme Court (the Court). In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Court issued a decision on June 21, 2005, affirming portions of the OCC’s order and remanding certain provisions. The Court affirmed the OCC’s finding that Lawton established a legally enforceable obligation and ruled that it was within the OCC’s discretion to award a 20-year contract and to base the capacity payment on a peaking unit. The Court directed the OCC to revisit its determination of PSO’s avoided energy cost. Hearings were held on the remanded issues in April and May 2006.

In April 2007, all parties in the case filed a settlement agreement with the OCC resolving all issues. The OCC approved the settlement agreement in April 2007. The settlement agreement provides for a purchase fee of $35 million to be paid by PSO to Lawton and for Lawton to provide, at PSO’s direction, all rights to the Lawton Cogeneration Facility for permits, options and engineering studies. PSO will record the purchase fee as a regulatory asset and recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service of its new peaking units to be located at the Southwestern Station and Riverside Station at the time these units are placed in service. PSO may request approval from the OCC for recovery of costs exceeding the cost cap if special circumstances occurred necessitating a higher level of costs. Such costs will continue to be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units. Once the cost recovery for the new peaking units begins in mid-2008, PSO expects annual revenues of an estimated $36 million related to cost recovery of the peaking units and the purchase fee. This settlement agreement was supported by the OCC Staff, the Attorney General, the Oklahoma Industrial Energy Consumers and Lawton Cogeneration, L.L.C.

Louisiana Rate Matters

SWEPCo Louisiana Compliance Filing - Affecting SWEPCo

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. Due to multiple delays, in April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed updated financial review schedules in May 2006 showing a return on equity of 9.44% compared to the previously authorized return on equity of 11.1%.

In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdiction customers, based on a proposed 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain ongoing operations and maintenance expense levels. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo filed rebuttal testimony in January 2007. A decision is not expected until mid or late 2007. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely impact future results of operations, cash flows and possibly financial condition.

FERC Rate Matters

Transmission Rate Proceedings at the FERC - Affecting APCo, CSPCo, I&M, KPCo and OPCo

The FERC PJM Regional Transmission Rate Proceeding

At AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP and other transmission owners for the regional transmission facilities they provide to PJM, which provides service for the benefit of customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC. This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway.

Parties to the regional rate proceeding proposed the following rate regimes:

- AEP/AP proposed a Highway/Byway rate design in which:
  - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The AEP/AP proposal would produce about $125 million in additional revenues per year for AEP from users in other zones of PJM.
  - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- Two other utilities, Baltimore Gas & Electric Company (BG&E) and Old Dominion Electric Cooperative (ODEC), proposed a Highway/Byway rate that includes transmission facilities above 200 kV, which would produce lower

revenues for AEP than the AEP/AP proposal.
- In another competing Highway/Byway proposal, a group of LSEs proposed rates that would include existing 500 kV and higher voltage facilities and new facilities above 200 kV in the Highway rate, which would produce considerably lower revenues for AEP than the AEP/AP proposal.
- In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or “Postage Stamp” type of rate design that would include all transmission facilities, which would produce higher transmission revenues for AEP than the AEP/AP proposal.

All of these proposals were challenged by a majority of other transmission owners in the PJM region, who favor continuation of the existing PJM rate design which provides AEP with no compensation for through and out traffic on its east zone transmission system. Hearings were held in April 2006 and the ALJ issued an initial decision in July 2006. The ALJ found the existing PJM zonal rate design to be unjust and determined that it should be replaced. The ALJ found that the Highway/Byway rates proposed by AEP/AP and BG&E/ODEC and the Postage Stamp rate proposed by the FERC staff to be just and reasonable alternatives. The ALJ also found FERC staff’s proposed Postage Stamp rate to be just and reasonable and recommended that it be adopted. The ALJ also found that the effective date of the rate change should be April 1, 2006 to coincide with SECA rate elimination. Because the Postage Stamp rate was found to produce greater cost shifts than other proposals, the judge also recommended that the design be phased-in. Without a phase-in, the Postage Stamp method would produce more revenue for AEP than the AEP/AP proposal. The phase-in of Postage Stamp rates would delay the full impact of that result until about 2012.

AEP filed briefs noting exceptions to the initial decision and replies to the exceptions of other parties. AEP argued that a phase-in should not be required. Nevertheless, AEP argued that if the FERC adopts the Postage Stamp rate and a phase-in plan, the revenue collections curtailed by the phase-in should be deferred and paid later with interest.

During 2006, the AEP East companies sought to increase retail rates in most of their states to recover lost T&O and SECA revenues. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of its share of the transmission revenue reduction in new rates effective March 30, 2006.
- In Ohio, CSPCo and OPCo recover their FERC-approved OATT that reflects their share of the full transmission revenue requirement retroactive to April 1, 2006 under a May 2006 PUCO order.
- In West Virginia, APCo settled a rate case, which provided for the recovery of its share of the T&O/SECA transmission revenue reduction beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of its share of the T&O/SECA transmission revenue reduction starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.
- In Michigan, I&M has not filed to seek recovery of the lost transmission revenues.

In April 2007, the FERC issued an order reversing the ALJ decision. The FERC ruled that the current PJM rate design is just and reasonable. The FERC further ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants. As a result of this order, the AEP East companies retail customers will be asked to bear the full cost of the existing AEP east transmission zone facilities. However, the AEP East companies customers will also be charged a share of the cost of new 500 kV and higher voltage transmission facilities built in PJM, of which the vast majority for the foreseeable future will not be needed by their customers, but will bolster service and reduce costs in other zones of PJM. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them as a result of this order, if upheld. AEP will request rehearing of this order. Management cannot estimate at this time what effect, if any, this order will have on their future construction of new east transmission facilities, results of operations, cash flows and financial condition.

The AEP East companies presently recover from retail customers approximately 85% of the reduction in transmission revenues of $128 million a year. Future results of operations, cash flows and financial condition will continue to be adversely affected in Indiana and Michigan until these lost transmission revenues are recovered in retail rates.

SECA Revenue Subject to Refund

The AEP East companies ceased collecting through-and-out transmission service (T&O) revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the 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 or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than 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 as follows:

Company	Year Ended December 31, 2006 (a)	2005	2004
	(in millions)		
APCo	$ 13.4	$ 52.4	$ 4.4
CSPCo	7.9	28.4	2.5
I&M	8.1	30.4	2.8
KPCo	3.2	12.4	1.0
OPCo	10.4	39.4	3.5

(a) Represents revenues through March 31, 2006, when SECA rates expired, and excludes all provisions for refund.

Approximately $19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

In August 2006, the 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 was not 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.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues.

The AEP East companies provided for net refunds as shown in the following table:

Company	Year Ended December 31, 2006	2005
	(in millions)	
APCo	$ 11.0	$ 1.0
CSPCo	6.1	0.6
I&M	6.4	0.6
KPCo	2.6	0.2
OPCo	8.3	0.8

In September 2006, AEP, together with Exelon and DP&L, filed an extensive post-hearing brief and reply brief 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 initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. Although management believes they have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2006 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 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, 2007, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, with maturities ranging from June 2007 to March 2008.

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 $85 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 46. 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, 2007, SWEPCo collected approximately $30 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, 2007, Registrant Subsidiaries entered into sale agreements including indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary except TCC. TCC sale agreements include indemnifications with a maximum exposure of $456 million related to the sale price of its generation assets. See “Texas Plants - South Texas Project”, “Texas Plants - TCC Generation Assets” and “Texas Plants - Oklaunion Power Station” sections of Note 8 of the 2006 Annual Report. 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. At March 31, 2007, 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	$	7
CSPCo		4
I&M		5
KPCo		2
OPCo		7
PSO		5
SWEPCo		6
TCC		6
TNC		3

CONTINGENCIES

Federal EPA Complaint and Notice of Violation - Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA, certain special interest groups and a number of states allege that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred at our generating units over a twenty-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke

Energy case.

Under the CAA, if a plant undertakes a major modification that results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord (12.5% owned), Zimmer (25.4% owned), and Stuart (26% owned) Stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. In April 2007, the Supreme Court denied the petition for review. The Federal EPA also proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

On April 2, 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define "major modification" in two different CAA provisions in the same way. The Court also found that the Fourth Circuit's interpretation of "major modification" as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on certain of the merits of the NSR proceedings brought against APCo, CSPCo, I&M and OPCo in U.S. District Court for the Southern District of Ohio, the U.S. Supreme Court's issuance of a ruling in the Duke Energy cases has an impact on the timing of our NSR proceedings. First, the court in the case for which a trial on liability issues has been conducted has indicated an intent to issue a decision on liability. Second, the bench trial on remedy issues, if necessary, is likely to be scheduled to begin in the third quarter of 2007.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, AEP subsidiaries might have for civil penalties under the CAA proceedings. 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 AEP subsidiaries do not prevail, management believes AEP subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If any of the AEP subsidiaries are 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. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled for the second quarter of 2007.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. 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 removing the heat input references from the Welsh permit and clarifying the sulfur content of fuels burned at the plant is limited to 0.5% on an as-received basis. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration.

Management is unable to predict the timing of any future action by TCEQ 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 defendant's 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 defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. On April 2, 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. Management believes the actions are without merit and intends to defend against the claims.

TEM Litigation - Affecting OPCo

OPCo 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 dated November 15, 2000 (PPA). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

In September 2003, TEM and OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo alleged that TEM breached the PPA, and sought a determination of its rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of OPCo's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In August 2005, a federal judge ruled that TEM had breached the contract and awarded damages to OPCo of $123 million plus prejudgment interest. Any eventual proceeds will be recorded as a gain when received.

In September 2005, TEM posted a $142 million letter of credit as security pending appeal of the judgment. Both parties filed Notices of Appeal with the United States Court of Appeals for the Second Circuit, which heard oral argument on the appeals in December 2006. Management cannot predict the ultimate outcome of this proceeding.

Coal Transportation Dispute - Affecting PSO, TCC and TNC

PSO, TCC, TNC, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded provisions for possible loss in 2004, 2005, 2006 and the first quarter of 2007. The provision was deferred as a regulatory asset under PSO's fuel mechanism and immaterially affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

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 work toward mitigating the disputed amounts to the extent possible.

Claims by the City of Brownsville, Texas Against TCC - Affecting TCC

On April 27, 2007, the City of Brownsville, Texas served its Fifth Amended Answer and Cross-Claims in litigation pending in the District Court of Dallas County, Texas. The cross-claims seek recovery against TCC based on allegations of breach of contract, breach of fiduciary duty, unjust enrichment, constructive trust, conversion, breach of the Texas theft liability act and fraud allegedly occurring in connection with a transaction in which Brownsville purchased TCC's interest in the Oklaunion electric generating station. Management believes that the claims are without merit and intends to defend against them vigorously.

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. In December 2002, a FERC ALJ ruled in AEP's favor and dismissed the complaint filed by the Nevada utilities. In 2001, the Nevada utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 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. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

5. ACQUISITIONS, DISPOSITIONS AND ASSETS HELD FOR SALE

ACQUISITIONS

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 approximately $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 - Affecting AEGCo

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. AEGCo will complete 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.

2006

None

DISPOSITIONS

2007

Texas Plants - Oklaunion Power Station - Affecting TCC

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville for $42.8 million plus adjustments. The sale did not have a significant effect on TCC's results of operations. See "Claims by the City of Brownsville, Texas Against TCC" section of Note 4.

2006

None

ASSETS HELD FOR SALE

Texas Plants - Oklaunion Power Station - Affecting TCC

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville. The sale did not have a significant effect on TCC's results of operations nor does TCC expect any remaining litigation to have a significant effect on its results of operations.

TCC's assets related to the Oklaunion Power Station were classified in Assets Held for Sale - Texas Generation Plant on TCC's Condensed Consolidated Balance Sheet at December 31, 2006. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by the Registrant Subsidiaries except TNC.

The Assets Held for Sale were as follows:

Texas Plants (TCC)	March 31, 2007	December 31, 2006
	(in millions)	
Assets:		
Other Current Assets	$ -	$ 1
Property, Plant and Equipment, Net	-	43
Total Assets Held for Sale - Texas Generation Plant	$ -	$ 44

6. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC 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, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC adopted SFAS 158 as of December 31, 2006. They recorded a SFAS 71 regulatory asset for their qualifying SFAS 158 costs of regulated operations that for ratemaking purposes will be deferred for future recovery.

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, 2007 and 2006:

	Pension Plans	Other Postretirement Benefit Plans

	2007	2006	2007	2006
		(in millions)		
Service Cost	$ 24	$ 24	$ 10	$ 10
Interest Cost	59	57	26	25
Expected Return on Plan Assets	(85)	(83)	(26)	(23)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	15	20	3	5
Net Periodic Benefit Cost	$ 13	$ 18	$ 20	$ 24

The following table provides the net periodic benefit cost (credit) for the plans by Registrant Subsidiary for the three months ended March 31, 2007 and 2006:

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Company		(in thousands)		
APCo	$ 842	$ 1,468	$ 3,560	$ 4,489
CSPCo	(257)	205	1,491	1,805
I&M	1,900	2,331	2,530	2,953
KPCo	255	358	426	513
OPCo	245	826	2,802	3,396
PSO	424	977	1,431	1,588
SWEPCo	746	1,225	1,419	1,578
TCC	101	773	1,575	1,696
TNC	70	325	631	715

7. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is an integrated electricity generation, transmission and distribution business except AEGCo, which is an electricity generation business, and TCC and TNC, which are transmission and distribution businesses. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. INCOME TAXES

We join in the filing of a consolidated federal income tax return with our subsidiaries in the American Electric Power (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 expense. The tax benefit of the parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

Audit Status

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

We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for years prior to 1997. We have effectively settled all outstanding proposed IRS adjustments for years 1997 through 1999 and through June 2000 for the CSW pre-merger tax period and anticipate payment for the agreed adjustments to occur during 2007. Returns for the years 2000 through 2003 are presently being audited by the IRS and we anticipate that the audit will be completed by the end of 2007.

The IRS has proposed certain significant adjustments to AEP's foreign tax credit and interest allocation positions. Management is currently evaluating those proposed adjustments to determine if it agrees, but if accepted, we do not anticipate the adjustments would result in a material change to our financial position.

FIN 48 Adoption

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the approximate increase (decrease) 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 was recognized by each Registrant Subsidiary as follows:

Company		**(in thousands)**
AEGCo	$	(27)
APCo		2,685
CSPCo		3,022
I&M		(327)
KPCo		786
OPCo		5,380
PSO		386
SWEPCo		1,642
TCC		2,187
TNC		557

At January 1, 2007, the total amount of unrecognized tax benefits under FIN 48 for each Registrant Subsidiary was as follows:

Company		**(in millions)**
AEGCo	$	0.1
APCo		21.7
CSPCo		25.0
I&M		18.2
KPCo		3.4
OPCo		49.8
PSO		8.9
SWEPCo		7.1
TCC		20.7
TNC		6.9

We believe it is reasonably possible that there will be a net decrease in unrecognized tax benefits due to the settlement of audits and the expiration of statute of limitations within 12 months of the reporting date for each Registrant

Subsidiary as follows:

Company	(in millions)
AEGCo	$ 0.5
APCo	5.5
CSPCo	9.3
I&M	6.0
KPCo	1.4
OPCo	9.0
PSO	4.4
SWEPCo	2.8
TCC	3.4
TNC	1.6

At January 1, 2007, the total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant Subsidiary was as follows:

Company	(in millions)
APCo	$ 5.4
CSPCo	13.8
I&M	5.4
KPCo	0.6
OPCo	23.4
PSO	1.2
SWEPCo	1.2
TCC	9.3
TNC	2.6

At January 1, 2007, tax positions for each Registrant Subsidiary, for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility was as follows:

Company	(in millions)
AEGCo	$ 0.1
APCo	13.7
CSPCo	3.9
I&M	10.3
KPCo	2.5
OPCo	14.2
PSO	7.1
SWEPCo	5.1
TCC	6.4
TNC	2.9

Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

Prior to the adoption of FIN 48, we recorded interest and penalty accruals related to income tax positions in tax accrual accounts. With the adoption of FIN 48, we began recognizing interest accruals related to income tax positions in interest income or expense as applicable, and penalties in operating expenses. As of January 1, 2007, each Registrant Subsidiary accrued for the payment of uncertain interest and penalties as follows:

Company	(in millions)
AEGCo	$ 0.1
APCo	4.6
CSPCo	1.7
I&M	2.8
KPCo	1.2
OPCo	4.3
PSO	2.7
SWEPCo	2.0
TCC	2.5
TNC	1.0

9. <u>FINANCING ACTIVITIES</u>

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2007 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
SWEPCo	Senior Unsecured Notes	$ 250,000	5.55	2017

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
OPCo	Notes Payable	$ 1,463	6.81	2008
OPCo	Notes Payable	6,000	6.27	2009
SWEPCo	Notes Payable	1,645	4.47	2011
SWEPCo	Notes Payable	4,000	6.36	2007
SWEPCo	Notes Payable	750	Variable	2008
TCC	Securitization Bonds	32,125	5.01	2008

In April 2007, OPCo issued $400 million of three-year floating rate notes at an initial rate of 5.53% due in 2010. The proceeds from this issuance will contribute to our investment in environmental equipment.

Lines of Credit and Short-term Debt - AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility 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, 2007 and December 31, 2006 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, 2007 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, 2007	Authorized Short-Term Borrowing Limit
			(in thousands)			
AEGCo	$ 75,425	$ -	$ 44,340	$ -	$ (29,997)	$ 125,000(a)
APCo	109,259	-	71,378	-	(82,860)	600,000
CSPCo	15,693	35,270	6,204	14,543	922	350,000
I&M	100,374	-	66,570	-	(45,759)	500,000
KPCo	46,317	-	30,845	-	(20,769)	200,000
OPCo	444,153	-	333,467	-	(397,127)	600,000
PSO	135,694	-	76,776	-	(135,694)	300,000
SWEPCo	240,786	48,979	215,207	30,267	8,959	350,000
TCC	-	394,180	-	295,542	216,953	600,000
TNC (b)	35,191	3,200	22,179	2,365	(24,487)	250,000

(a) In April 2007, limit increased by $285 million under regulatory orders.
(b) Does not include short-term lending activity of TNC's wholly-owned subsidiary, AEP Texas North Generation Company LLC (TNGC), who is a participant in the Nonutility Money Pool. As of March 31, 2007, TNGC had $13.3 million in outstanding loans to the Nonutility Money Pool.

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, 2007	2006
Maximum Interest Rate	5.43%	4.85%
Minimum Interest Rate	5.30%	4.37%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 2007 and 2006 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for	Average Interest Rate for Funds Loaned to the Utility Money Pool for

	Three Months Ended March 31,		Three Months Ended March 31,	
	2007	2006	2007	2006
Company		(in percentage)		
AEGCo	5.34	4.57	-	-
APCo	5.34	4.60	-	-
CSPCo	5.35	4.58	5.33	4.66
I&M	5.34	4.59	-	-
KPCo	5.34	4.54	-	4.75
OPCo	5.34	4.60	-	-
PSO	5.34	4.63	-	-
SWEPCo	5.35	4.60	5.34	-
TCC	-	4.47	5.34	4.68
TNC (a)	5.34	4.57	5.34	4.54

(a) Does not include short-term lending activity for TNGC, who is a participant in the Nonutility Money Pool. For the three months ended March 31, 2007, the average interest rate for funds loaned to the Nonutility Money Pool by TNGC was 5.31%.

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

		March 31, 2007		December 31, 2006	
Company	Type of Debt	Outstanding Amount (in millions)	Interest Rate	Outstanding Amount (in millions)	Interest Rate
OPCo	Commercial Paper - JMG	$ 5	5.56%	$ 1	5.56%
SWEPCo	Line of Credit - Sabine	20	6.52%	17	6.38%

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 2006 Annual Report should also be read in conjunction with this report.

Significant Factors

Ohio New Generation

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 during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over no more than a twelve-month period effective July 1, 2006. Through March 31, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each recovered $9 million of those costs. CSPCo and OPCo will recover the remaining amounts through June 30, 2007. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all charges collected for pre-construction costs, associated with items that may be utilized in IGCC projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. CSPCo and OPCo believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase I cost-related recoveries.

SECA Revenue Subject to Refund

The AEP East Companies ceased collecting through-and-out transmission service (T&O) revenues in accordance with FERC orders and implemented SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. In August 2006, the 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 was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies have reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. In the second half of 2006, the AEP East companies provided a reserve of $37 million in net refunds.

In September 2006, AEP, together with Exelon and the Dayton Power and Light Company, filed an extensive post hearing brief and reply brief 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 initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. Although management believes they have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will 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 Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (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 carbon dioxide (CO_2) emissions to address concerns about global climate change.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and thereafter against nonaffiliated utilities including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at the Registrant Subsidiaries' power plants occurred over a twenty-year period. A bench trial on the liability issues was held during 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants have reached different results. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. In April 2007, the Supreme Court denied the petition for review. The Federal EPA also proposed a rule that would define "emissions increases" in a way that would exclude most of the challenged activities from NSR.

On April 2, 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define "major modification" in two different CAA provisions in the same way. The Court also found that the Fourth Circuit's interpretation of "major modification" as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on certain of the merits of the NSR proceedings brought against APCo, CSPCo, I&M and OPCo in U.S. District Court for the Southern District of Ohio, the U.S. Supreme Court's issuance of a ruling in the Duke Energy cases has an impact on the timing of our NSR proceedings. First, the court in the case for which a trial on liability issues has been conducted has indicated an intent to issue a decision on liability. Second, the bench trial on remedy issues, if necessary, is likely to be scheduled to begin in the third quarter of 2007.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, the Registrant Subsidiaries might have for civil penalties under the CAA proceedings. 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 to be determined by the court. If the Registrant Subsidiaries do not prevail, management believes the Registrant Subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If the Registrant Subsidiaries are 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.

Adoption of New Accounting Pronouncements

FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. The Registrant Subsidiaries adopted FIN 48 effective January 1, 2007. See "FIN 48 "Accounting for Uncertainty in Income Taxes"" section of Note 2 and see Note 8 - Income Taxes. The impact of this interpretation was an unfavorable (favorable) adjustment to retained earnings as follows:

Company		(in thousands)
AEGCo	$	(27)

APCo	2,685
CSPCo	3,022
I&M	(327)
KPCo	786
OPCo	5,380
PSO	386
SWEPCo	1,642
TCC	2,187
TNC	557

CONTROLS AND PROCEDURES

During the first quarter of 2007, management, including the principal executive officer and principal financial officer of each of AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (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, 2007 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.

The only 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 2007 that materially affected, or is reasonably likely to materially affect, the Registrants' internal controls over financial reporting, relates to the Southwest Power Pool's (SPP) implementation of an Energy Imbalance Service Market. In connection with this market implementation, two of AEP's subsidiaries (Public Service Company of Oklahoma and Southwestern Electric Power Company) implemented or modified a number of business processes and controls to facilitate participation in, and resultant settlement within, the SPP Energy Imbalance Service Market.

PART II. OTHER INFORMATION

Item 1. <u>Legal Proceedings</u>

For a discussion of material legal proceedings, see Note 4, *Commitments, Guarantees and Contingencies,* incorporated herein by reference.

Item 1A. <u>Risk Factors</u>

Our Annual Report on Form 10-K for the year ended December 31, 2006 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 2006 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Our request for rate recovery of additional costs may not be approved in Virginia. *(Applies to AEP and APCo.)*

APCo filed a request with the Virginia SCC in May 2006 seeking a net increase in base rates of $198 million to recover increasing costs, including a return on equity of 11.5%. APCo also requested to apply its off-system sales margins (currently credited to customers through base rates) to the fuel factor where they can be adjusted annually. APCo also requested to retain a portion of the off-system sales margins. In May 2006, the Virginia SCC issued an order placing the net requested base rate increase into effect as of October 2, 2006, subject to refund. In October 2006, the Virginia SCC staff filed direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. APCo has filed rebuttal testimony and hearings were held in December 2006. In March 2007, the Hearing Examiner released a report recommending a base rate increase of $31 million with a return on equity of 10.1% and a 5% retention of off-system sales margin sharing. If the Virginia SCC denies the requested rate recovery, it could adversely impact future results of operations, cash flows and financial condition.

Our request for rate recovery of additional costs may not be approved in Texas. *(Applies to AEP, TCC and TNC.)*

TCC and TNC have filed requests with the PUCT to increase their transmission and distribution rates. The rate requests include the amounts charged for the delivery of electricity over TCC´s and TNC´s transmission and distribution lines. TCC is seeking approval of an $81 million increase, which includes the expiration of $20 million in billing credits that the PUCT required in approving the merger of CSW into AEP. The credits have been in place since 2000. TNC is seeking approval of a $25 million increase, which includes the expiration of $6 million in billing credits. TCC and TNC are requesting a return on equity of 11.25% with a capital structure of approximately 60% debt/40% equity. As part of rebuttal testimony filed in April 2007, TCC and TNC reduced their base rate request by $11 million and $3 million, respectively, and reduced their return on equity by 0.5%. If the PUCT denies the requested rate recovery, it could adversely impact future results of operations, cash flows and financial condition.

Our request for rate recovery of additional costs may not be approved in Oklahoma. *(Applies to AEP and PSO.)*

PSO filed a request with the OCC in November 2006 seeking approval of a $50 million overall increase in base rates, an annually adjusted rate mechanism to recover the expected significant investment PSO will be making in new facilities, several new and restructured tariffs to allow PSO to begin to reduce the relationship between its revenues and its sales volumes, and to implement some demand side management tariffs. PSO´s planned investments over the next five years include new generation facilities ($1.12 billion), new and refurbished transmission substations and lines ($302 million) and new distribution lines and equipment ($582 million). In April 2007, PSO filed rebuttal testimony regarding various issues raised by the OCC Staff and the intervenors. As part of rebuttal testimony, PSO reduced its base rate request by $2 million. If the OCC denies the requested rate recovery, it could adversely impact future results of operations, cash flows and financial condition.

The amount we charged third parties for using our transmission facilities has been reduced, is subject to refund and may not be completely restored in the future. *(Applies to AEP and the AEP East companies.)*

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective tariffs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within those RTOs. The elimination of the T&O rates reduces the transmission service revenues collected by the RTOs and thereby reduces the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost allocation (SECA) transition rates beginning in December 2004 and extending through March 2006. Intervenors objected to this decision; therefore the SECA fees we collected ($220 million) are subject to refund. Approximately $19 million of the SECA revenues that we billed were never collected. AEP filed a motion with the FERC to force payment of these SECA billings.

A hearing was held in May 2006 to determine whether any of the SECA revenues should be refunded. In August 2006, the 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 was not 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 unpaid SECA rates must be paid in the recommended reduced amount. The FERC has not ruled on the matter. If the FERC upholds the decision of the ALJ, up to $126 million of collected SECA rates could be refunded by the AEP East companies. We have recorded provisions in the aggregate amount of $37 million related to the potential refund of SECA rates pending settlement negotiations with various intervenors.

SECA transition rates expired on March 31, 2006 and did not fully compensate AEP East companies for ongoing lost T&O revenues. As a result of rate relief in certain jurisdictions, however, approximately 85% of the ongoing lost T&O revenues are now being recovered from native load customers of AEP East companies in those jurisdictions. The portion attributable to Virginia is being collected subject to refund.

In addition to seeking retail rate recovery from native load customers in the applicable states, AEP and another member of PJM have filed an application with the FERC seeking compensation from other unaffiliated members of PJM for the costs associated with those members' use of the filers' the AEP East companies respective transmission assets. A majority of PJM members have filed in opposition to the proposal. Hearings were held in April 2006. An ALJ recommended a rate design that would result in greater recovery for AEP than the proposal AEP had submitted. The ALJ also recommended, however, that the design be phased-in, which could limit the amount of recovery for AEP. In April 2007, the FERC issued an order reversing the ALJ decision. The FERC ruled that the current PJM rate design is just and reasonable. The FERC further ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants. Management cannot estimate at this time what affect, if any, this order will have on our future construction of new east transmission facilities, results of operations, cash flows and financial condition.

We are exposed to losses resulting from the bankruptcy of Enron Corp. *(Applies to AEP.)*

On June 1, 2001, we purchased HPL from Enron Corp. (Enron). Later that year, Enron and its subsidiaries filed bankruptcy proceedings in the U.S. Bankruptcy Court for the Southern District of New York. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 BCF of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (together with BOA, BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Additionally, 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, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. We purchased 10 BCF of gas from Enron and are currently litigating the rights to the remaining 55 BCF of cushion gas.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. In 2005, we sold HPL, including the Bammel gas storage facility. We indemnified the purchaser for damages, if any, arising from the litigation with BOA. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Risks Relating To State Restructuring

In Ohio, our costs may not be recovered and rates may be reduced. *(Applies to AEP, OPCo and CSPCo.)*

In January 2005, the PUCO approved RSPs for CSPCo and OPCo. The RSPs provide, among other things, for CSPCo and OPCo to raise their generation rates on an annual basis through 2008 by 3% and 7%, respectively. The RSPs also provide for possible additional annual generation rate increases of up to an average of 4% per year for specified costs. The RSPs also provide that CSPCo and OPCo can recover certain environmental carrying costs, PJM-related administrative costs and certain congestion costs. In 2006, CSPCo and OPCo collected an additional estimated $244 million in gross margin as a result of the RSPs. This amount is expected to increase in 2007 and 2008.

In 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the validity of the RSPs under Ohio's electricity restructuring law. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP orders for CSPCo and OPCo and remanded the case to the PUCO for further proceedings.

In August 2006, the PUCO directed CSPCo and OPCo to file a plan providing an option for customer participation in the electric market through competitive bids or other reasonable means. The PUCO also held that the RSPs shall remain effective. Accordingly, CSPCo and OPCo continued collecting RSP revenues. In September 2006, CSPCo and OPCo submitted their proposals to provide additional options for customer participation in the electric market.

In March 2007, CSPCo and OPCo filed a settlement agreement at the PUCO resolving the Ohio Supreme Court's remand of the PUCO's RSP order. Management expects the PUCO will approve this settlement agreement.

Some laws and regulations governing restructuring in Virginia have not yet been interpreted or adopted and could harm our business, operating results and financial condition. *(Applies to AEP and APCo.)*

Virginia restructuring legislation was enacted in 1999 providing for retail choice of generation suppliers to be phased in over two years beginning January 1, 2002. It required jurisdictional utilities to unbundle their power supply and energy delivery rates and to file functional separation plans by January 1, 2002. APCo filed its plan with the Virginia SCC and, following Virginia SCC approval of a settlement agreement, now operates in Virginia as a functionally separated electric utility charging unbundled rates for its retail sales of electricity. The settlement agreement addressed functional separation, leaving decisions related to legal separation for later Virginia SCC consideration. While the electric restructuring law in Virginia established the general framework governing the retail electric market, it required the Virginia SCC to issue rules and determinations implementing the law.

In April 2007, Virginia enacted a law providing for cost-based regulation of electric utilities' generation/supply rates. With the return of cost-based regulation, APCo's generation business will again meet the criteria for application of regulatory accounting principles under SFAS 71. Results of operations and financial condition could be adversely affected if and when APCo is required to re-establish certain net regulatory liabilities applicable to its generation/supply business. The timing and one-time earnings effect from such reapplication of SFAS 71 regulatory accounting for APCo's Virginia generation/supply business are uncertain at this time.

There is uncertainty as to our recovery of stranded costs resulting from industry restructuring in Texas. *(Applies to AEP and TCC.)*

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. We have appealed the PUCT's final order seeking additional recovery consistent with the Texas Restructuring Legislation and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. In a preliminary ruling filed in February 2007, the Texas state district court (District Court) adjudicating the appeal of the final order in the true-up proceeding found that the PUCT erred in several respects, including the method used to determine stranded costs and the awarding of certain carrying costs. Following the preliminary ruling, the court granted a rehearing of the issue regarding the method to determine stranded costs.

In March 2007, the District Court judge reversed the earlier preliminary decision concluding the sale of assets method to value TCC's nuclear plant was appropriate. It is expected that the parties and intervenors will appeal various portions of the District Court ruling along with other items to the Texas Court of Appeals. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our costs of compliance with environmental laws are significant and the cost of compliance with future environmental laws could harm our cash flow and profitability. *(Applies to AEP and each Registrant Subsidiary other than TCC and TNC.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. On April 2, 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. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from our estimates. All of the costs are incremental to our current investment base and operating cost structure.

If Federal and/or State requirements are imposed on electric utility companies mandating further emission reductions, including limitations on CO_2 emissions, such requirements could make some of our electric

generating units uneconomical to maintain or operate. *(Applies to AEP and each Registrant Subsidiary other than TCC and TNC.)*

Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have advanced through the legislature. On April 2, 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. Future changes in environmental regulations governing these pollutants could make some of our electric generating units uneconomical to maintain or operate. In addition, any legal obligation that would require us to substantially reduce our emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. While mandatory requirements for further emission reductions from our fossil fleet do not appear to be imminent, we continue to monitor regulatory and legislative developments in this area.

Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations. *(Applies to AEP and each Registrant Subsidiary other than TCC and TNC.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the Federal EPA and various states filed against us highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities, in particular.

Since 1999, we have been involved in litigation regarding generating plant emissions under the CAA. The Federal EPA and a number of states alleged that we and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the CAA. The Federal EPA filed complaints against certain AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded and the court has indicated an intent to issue a decision on liability. Additionally, in July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal common law. The trial court dismissed the suits and plaintiffs have appealed the dismissal. While we believe the claims are without merit, the costs associated with reducing CO_2 emissions could harm our business and our results of operations and financial position.

If these or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

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, 2007 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	Average Price

	of Shares Purchased	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
01/01/07 - 01/31/07	30(a)	$ 79	-	$ -
02/01/07 - 02/28/07	-	-	-	-
03/01/07 - 03/31/07	-	-	-	-

(a) OPCo repurchased 30 shares of its 4.40% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.

Item 5. Other Information

NONE

Item 6. Exhibits

AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

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

AEP

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

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

31(b) - Certification of Registrant Subsidiaries' Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(d) - Certification of Registrant Subsidiaries' Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

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

AEP GENERATING COMPANY
AEP TEXAS CENTRAL COMPANY
AEP TEXAS NORTH COMPANY
APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
KENTUCKY 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 4, 2007