AMERICAN ELECTRIC POWER CO INC
Form 10-Q
August 04, 2006

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

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **June 30, 2006**
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 North Company, Columbus Southern 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.

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2006, the last trading date of the registrants' most recently completed second fiscal quarter	Number of shares of common stock outstanding of the registrants at July 31, 2006
AEP Generating Company	None	1,000
		($1,000 par value)
AEP Texas Central Company	None	2,211,678
		($25 par value)
AEP Texas North Company	None	5,488,560
		($25 par value)
American Electric Power Company, Inc.	$13,492,667,933	393,975,064
		($6.50 par value)
Appalachian Power Company	None	13,499,500
		(no par value)
Columbus Southern Power Company	None	16,410,426
		(no par value)
Indiana Michigan Power Company	None	1,400,000
		(no par value)
Kentucky Power Company	None	1,009,000
		($50 par value)
Ohio Power Company	None	27,952,473
		(no par value)
Public Service Company of Oklahoma	None	9,013,000
		($15 par value)
Southwestern Electric Power Company	None	7,536,640
		($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
June 30, 2006

	Exhibit 10(a)
	Exhibit 12
	Exhibit 31(a)
	Exhibit 31(b)
	Exhibit 31(c)
	Exhibit 31(d)
	Exhibit 32(a)
	Exhibit 32(b)

SIGNATURE

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
ADFIT	Accumulated Deferred Federal Income Taxes.
ADITC	Accumulated Deferred Investment Tax Credits.
AEGCo	AEP Generating Company, an AEP electric generating subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated entities.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
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.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
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 their 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.
EDFIT	Excess Deferred Federal Income Taxes.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EPACT	Energy Policy Act of 2005.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.

FERC	Federal Energy Regulatory Commission.
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipe Line Company LP, a former AEP subsidiary that was sold in January 2005.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IPP	Independent Power Producers.
IURC	Indiana Utility Regulatory Commission.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
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.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PURPA	Public Utility Regulatory Policies Act of 1978.
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.
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 FASB.
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SIA	System Integration Agreement.

SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
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.
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 and costs of, 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 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.
- Our ability to sell assets at acceptable prices and other acceptable terms.
- 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.
- Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
- 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 implementation of EPACT and membership in and integration into regional transmission structures.
- 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.

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

EXECUTIVE OVERVIEW

Several factors contributed to our positive performance in the second quarter of 2006. We received favorable outcomes in various regulatory activities causing increased revenues. We also continued to win new power supply contracts with municipal and cooperative customers and our barging subsidiary is producing strong results. Some of these positive factors were offset in part by mild weather and increased fuel costs.

Regulatory Activity

Our significant regulatory activity progressed with the following major developments:

- In April 2006, the PUCO approved our recovery of the pre-construction costs for the IGCC clean-coal plant in Meigs County, Ohio. We subsequently submitted tariffs and received PUCO approval to recover $24 million of our IGCC pre-construction costs beginning July 1, 2006.
- In May 2006, we filed a base rate case in Virginia requesting a net rate increase of $198 million. Rates will be effective, subject to refund, on October 2, 2006.
- In May 2006, the PUCO approved a two-step increase in transmission rates with an over/under recovery mechanism effective April 1, 2006. We subsequently submitted tariffs and received PUCO approval to implement the rates in June 2006. We expect this order to increase 2006 revenues by $63 million.
- In June 2006, we received a financing order from the PUCT to issue $1.7 billion in securitization bonds. We anticipate issuing the bonds and receiving the proceeds by the end of September 2006. We intend to use the proceeds to reduce a portion of TCC's debt and equity, which would include a dividend payment to AEP.
- In July 2006, an ALJ rendered an initial decision to the FERC recommending that current transmission rates in PJM are unjust and unreasonable and should be redesigned to replace the PJM license plate rates effective April 1, 2006. If approved by the FERC, the new regional rates should result in parties outside of the AEP zone in PJM contributing a significant portion of AEP's transmission revenue requirement, some of which may be treated as a credit to retail customers. The favorable impact of the initial ALJ decision is not determinable pending the decision of the FERC and subject to analysis of credits to retail customers, if any.
- In July 2006, the FERC approved our request for use of an incentive rate treatment for our proposed 550-mile I-765 transmission line project. The approval is conditioned upon PJM including the project in its formal Regional Transmission Expansion Plan, which should be finalized in 2006 or early 2007.
- In July 2006, the West Virginia Public Service Commission approved a settlement agreement in APCo and WPCo's base rate case, providing for a $44 million annual increase in rates effective July 28, 2006. These rates include a surcharge for recovery of the cost of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.

Fuel Costs

During 2006, spot market prices for coal and natural gas have softened. In contrast, market prices for fuel oil have continued to increase. However, even considering softening fuel markets and favorable transportation effects during the first half of the year, we still expect an approximate eleven percent increase in coal costs during 2006, and we have price risk related to these commodity prices. More specifically, we do not have active fuel cost recovery adjustment mechanisms in Indiana and Ohio, which represents approximately 20% of our fuel costs.

In Indiana, our fuel recovery mechanism is temporarily capped, subject to preestablished escalators, at a fixed rate through June 2007. As a consequence of the cap, we incurred under-recoveries of $12 million for the first six months of 2006 and expect additional under-recoveries for the remainder of 2006. Our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans, which are presently subject to an Ohio Supreme Court remand. These increased rates, along with the reinstated fuel cost adjustment rate clause for over- or under-recovery of fuel and related costs effective July 1, 2006 in West Virginia, will help offset future negative impacts of fuel prices on our gross margins.

Barging Operations

During 2006, we have achieved favorable results in our Investments - Other segment primarily due to our barging operations. AEP MEMCO LLC (MEMCO) handles the dispatching and logistics for our river operations, which consists primarily of coal deliveries to our plants, coal movement between plants for ensuring continued operations when market disruptions occur and transportation of bargeable commodities for third parties. MEMCO continues to benefit from strong market demand for barging services as well as a tight supply of barges, which allowed it to negotiate very favorable annual freight contracts for 2006 and beyond for hauling a variety of commodities for third parties. The strong freight market, enhanced operating conditions when compared with the flooding and ice encountered during the first quarter of 2005 and the continued implementation of programs to maximize equipment use all contribute to an increase in tonnage transported and a related increase in earnings.

Stock Option Grant Practices

Our internal audit function recently completed a review of our stock option grant practices. The review was initiated as a matter of prudence resulting from our desire to ensure we had not engaged in the kinds of past practices that have recently received adverse publicity and resulted in investigations of other companies. Our internal auditors found no indication of backdating or special option grant timing.

RESULTS OF OPERATIONS

Segments

Our principal operating business segments and their major activities are:

Utility Operations

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

Investments - Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.

Our consolidated Income Before Discontinued Operations for the three and six months ended June 30, 2006 and 2005 were as follows (Earnings and Weighted Average Basic Shares Outstanding in millions):

	Three Months Ended June 30,	Six Months Ended June 30,

	2006		2005		2006		2005	
	Earnings	EPS (c)	Earnings	EPS (c)	Earnings	EPS (c)	Earnings	EPS (c)
Utility Operations	$ 160	$ 0.41	$ 247	$ 0.64	$ 525	$ 1.33	$ 600	$ 1.54
Investments - Other	13	0.03	(1)	-	29	0.08	4	0.01
All Other (a)	(3)	-	(26)	(0.06)	(5)	(0.01)	(40)	(0.10)
Investments - Gas Operations (b)	2	-	(2)	(0.01)	1	-	8	0.02
Income Before Discontinued Operations	$ 172	$ 0.44	$ 218	$ 0.57	$ 550	$ 1.40	$ 572	$ 1.47
Weighted Average Number of Basic Shares Outstanding		394		384		394		389

(a) All Other includes the parent company's interest income and expense, as well as other nonallocated costs.
(b) We sold our remaining gas pipeline and storage assets in 2005.
(c) 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.

Second Quarter of 2006 Compared to Second Quarter of 2005

Income Before Discontinued Operations in the second quarter of 2006 decreased $46 million compared to the second quarter of 2005 due to an $87 million decrease in Utility Operations earnings primarily related to decreases in off-system sales and transmission revenues and increases in operating expenses, partially offset by new rates implemented in Ohio and Kentucky. The decrease in Utility Operations earnings was partially offset by an earnings increase of $14 million in our Investments - Other segment primarily related to favorable results in our barging operations and a decrease of $23 million in All Other related to interest expense, net of interest income, at the parent company.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Income Before Discontinued Operations for the six months ended June 30, 2006 decreased $22 million compared to the six months ended June 30, 2005 due to a $75 million decrease in Utility Operations earnings primarily related to decreases in off-system sales and transmission revenues and increases in operating expenses, partially offset by new rates implemented in Ohio and Kentucky. The decrease in Utility Operations earnings was partially offset by an earnings increase of $25 million in our Investments - Other segment primarily related to favorable results in our barging operations and a decrease of $35 million in interest expense, net of interest income, at the parent company.

Our results of operations are discussed below according to our operating segments.

Utility Operations

Our Utility Operations include 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. Gross margins represent utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	Three Months Ended June 30,	Six Months Ended June 30,

	2006	2005	2006	2005
		(in millions)		
Revenues	$ 2,799	$ 2,702	$ 5,768	$ 5,386
Fuel and Purchased Energy	1,126	988	2,253	1,911
Gross Margin	1,673	1,714	3,515	3,475
Depreciation and Amortization	339	317	672	635
Other Operating Expenses	987	938	1,833	1,743
Operating Income	347	459	1,010	1,097
Other Income, Net	43	49	85	79
Interest Expense and Preferred Stock Dividend	160		314	
Requirements		156		300
Income Tax Expense	70	105	256	276
Income Before Discontinued Operations	$ 160	$ 247	$ 525	$ 600

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three and Six Months Ended June 30, 2006 and 2005

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
		(in millions of KWH)		
Energy Summary				
Retail:				
Residential	9,590	9,956	22,528	23,180
Commercial	9,440	9,573	18,349	18,305
Industrial	13,716	13,480	26,937	26,253
Miscellaneous	625	639	1,214	1,284
Subtotal	33,371	33,648	69,028	69,022
Texas Retail and Other	138	161	206	389
Total Retail	33,509	33,809	69,234	69,411
Wholesale	10,822	11,745	21,667	24,380
Texas Wires Delivery	6,915	6,736	12,461	12,254
Total KWHs	51,246	52,290	103,362	106,045

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 quarter and year-to-date periods ended June 30, 2006 and 2005 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
		(in degree days)		
Weather Summary				
Eastern Region				

Actual - Heating (a)	107	165	1,563	1,939
Normal - Heating (b)	175	177	1,992	1,988
Actual - Cooling (c)	228	288	229	288
Normal - Cooling (b)	279	278	282	281
Western Region (d)				
Actual - Heating (a)	5	26	663	795
Normal - Heating (b)	33	33	1,005	1,005
Actual - Cooling (c)	815	681	858	701
Normal - Cooling (b)	652	644	669	662

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the 30-year average of degree days.
(c) Eastern Region and Western Region cooling days are calculated on a 65 degree temperature base.
(d) Western Region statistics represent PSO/SWEPCo customer base only.

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006
Income from Utility Operations Before Discontinued Operations
(in millions)

Second Quarter of 2005		$ 247
Changes in Gross Margin:		
Retail Margins	56	
Off-system Sales	(49)	
Transmission Revenues	(55)	
Other	7	
Total Change in Gross Margin		(41)
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	(34)	
Depreciation and Amortization	(22)	
Taxes Other Than Income Taxes	(15)	
Other Income, Net	(6)	
Interest and Other Charges	(4)	
Total Change in Operating Expenses and Other		(81)
Income Tax Expense		35
Second Quarter of 2006		$ 160

Income from Utility Operations Before Discontinued Operations decreased $87 million to $160 million in 2006. The key drivers of the decrease were a $41 million net decrease in Gross Margin and an $81 million increase in Operating Expenses and Other, partially offset by a $35 million decrease in Income Tax Expense.

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

- Retail Margins increased $56 million primarily due to the following:
  - A $55 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our Rate Stabilization Plans (RSPs) and a $10 million increase related to new rates implemented in Kentucky as approved in our base rate case;
  - A $30 million increase in financial transmission rights revenue, net of congestion costs, due to improved management of price risk related to serving retail load within PJM under current transmission constraints;
  - An $18 million increase related to reduced off-system sales margins shared with customers due to lower off-system sales; and
  - A $14 million increase related to increased usage and customer growth in the industrial and commercial classes of which $11 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005; partially offset by
  - A $68 million increase in delivered fuel costs, which relates to the AEP East companies with inactive, capped or frozen fuel clauses; and
  - An $11 million decrease in usage related to mild weather. As compared to the prior year, our eastern region experienced a 21% decrease in cooling degree days, partially offset by a 20% increase in cooling degree days in the western region.
- Margins from Off-system Sales for 2006 decreased $49 million due to lower volumes in part from the sale of STP in May 2005, a forced outage in 2006 at the Oklaunion plant, various eastern fleet outages in 2006 for boiler tube inspections and lower optimization activities.
- Transmission Revenues decreased $55 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $18 million recorded in the second quarter of 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, SECA revenues have not been replaced. See the “SECA Revenue Subject to Refund” section of Note 3.

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

- Maintenance and Other Operation expenses increased $34 million primarily due to increases in generation expenses for planned and forced plant outages, increases in transmission and distribution expenses related to tree trimming and storm restoration and the establishment of a regulatory asset for PJM administrative fees in 2005 which reduced expenses in the prior period, offset by decreases related to the sale of STP in May 2005.
- Depreciation and Amortization expense increased $22 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases as well as higher depreciable property balances.
- Taxes Other Than Income Taxes increased $15 million primarily due to increased real and personal property taxes.
- Income Tax Expense decreased $35 million due to the decrease in pretax income.

<u>Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005</u>

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006
Income from Utility Operations Before Discontinued Operations
(in millions)

Six Months Ended June 30, 2005		$	600
Changes in Gross Margin:			
Retail Margins	168		
Off-system Sales	(73)		
Transmission Revenues	(54)		
Other	(1)		
Total Change in Gross Margin			40
Changes in Operating Expenses and Other:			
Maintenance and Other Operation	(28)		
Gain on Sales of Assets, Net	(46)		
Depreciation and Amortization	(37)		
Taxes Other Than Income Taxes	(16)		
Other Income, Net	6		
Interest and Other Charges	(14)		
Total Change in Operating Expenses and Other			(135)
Income Tax Expense			20
Six Months Ended June 30, 2006		$	525

Income from Utility Operations Before Discontinued Operations decreased $75 million to $525 million in 2006. The key driver of the decrease was a $135 million increase in Operating Expenses and Other, offset by a $40 million increase in Gross Margin and a $20 million decrease in Income Tax Expense.

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

· Retail Margins increased $168 million primarily due to the following:
  · A $103 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs, a $10 million increase related to new rates implemented in Kentucky as approved in our base rate case and a $7 million increase related to new rates implemented in Oklahoma in June 2005;
  · A $76 million increase in financial transmission rights revenue, net of congestion costs, due to improved management of price risk related to serving retail load within PJM under current transmission constraints;
  · A $41 million increase related to increased usage and customer growth in the industrial and commercial classes of which $21 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005;
  · An $18 million increase related to reduced off-system sales margins shared with customers due to lower off-system sales; and
  · A $29 million increase related to increased sales to municipal, cooperative and other wholesale customers primarily as a result of new power supply contracts; partially offset by
  · A $109 million increase in delivered fuel cost, which relates to AEP East companies with inactive, capped or frozen fuel clauses; and
  · A $37 million decrease in usage related to mild weather. As compared to the prior year, our eastern region and western region experienced 19% and 17% declines, respectively, in heating degree days. These decreases were

partially offset by an increase of 22% in cooling degree days in the western region.

- Margins from Off-system Sales for 2006 were $73 million lower than in 2005 due to lower volumes in part from the sale of STP in May 2005, a forced outage in 2006 at the Oklaunion plant, various eastern fleet outages in 2006 for boiler tube inspections and lower optimization activities.
- Transmission Revenues decreased $54 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $19 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, SECA revenues have not been replaced. See the "SECA Revenue Subject to Refund" section of Note 3.

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

- Maintenance and Other Operation expenses increased $28 million primarily due to increases in generation expenses related to base operations, maintenance and planned and forced plant outages, distribution expenses related to tree trimming and the establishment of a regulatory asset for PJM administrative fees in 2005 which reduced expenses in the prior period, offset by favorable variances related to expenses from the January 2005 ice storm in Ohio and Indiana and decreases related to the sale of STP in May 2005.
- Gain on Sales of Assets, Net decreased $46 million resulting from revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase-and-sale agreement from the sale of our REPs in 2002. In 2005, we reached a settlement with Centrica and received $112 million related to two years of earnings sharing whereas in 2006 we received $70 million related to one year of earnings sharing.
- Depreciation and Amortization expense increased $37 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases as well as higher depreciable property balances.
- Taxes Other Than Income Taxes increased $16 million primarily due to increased real and personal property taxes.
- Interest and Other Charges increased $14 million from the prior period primarily due to additional debt issued in late 2005 and early 2006 and increasing interest rates.
- Income Tax Expense decreased $20 million due to the decrease in pretax income.

Investments - Other

Second Quarter of 2006 Compared to Second Quarter of 2005

Income Before Discontinued Operations from our Investments - Other segment increased from a loss of $1 million in 2005 to income of $13 million in 2006. The increase was primarily due to favorable barging activity at MEMCO due to strong demand and a tight supply of barges, resulting in increased barge freight rates.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Income Before Discontinued Operations from our Investments - Other segment increased $25 million primarily due to favorable barging activity at MEMCO due to strong demand and a tight supply of barges which increased barge freight rates. Additionally, the first quarter of 2006 operating conditions for our barging operations improved from 2005 when severe ice and flooding caused increased operating costs.

Other

Parent

Second Quarter of 2006 Compared to Second Quarter of 2005

The parent company's Loss before Discontinued Operations decreased $23 million from 2005 primarily due to lower interest expense and associated buyback costs related to the redemption of $550 million of senior unsecured notes in April 2005 and increased affiliated interest income related to favorable results from the corporate borrowing program.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

The parent company's Loss before Discontinued Operations decreased $35 million from 2005 primarily due to lower interest expense and associated buyback costs related to the redemption of $550 million of senior unsecured notes in April 2005 and increased affiliated interest income related to favorable results from the corporate borrowing program.

Investments - Gas Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

Income Before Discontinued Operations from our Gas Operations segment increased from a loss of $2 million in 2005 to income of $2 million in 2006. The increase primarily relates to a true-up adjustment in the second quarter of 2006 related to the Enron litigation settled in the fourth quarter of 2005. Current year results also relate to gas contracts that were not sold with the gas pipeline and storage assets.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Income Before Discontinued Operations from our Gas Operations segment of $1 million in 2006 compares with $8 million of income recorded for 2005. Prior year results included one month of HPL's operations due to the sale of HPL in January 2005. Current year results relate to gas contracts that were not sold with the gas pipeline and storage assets.

AEP System Income Taxes

The decrease in income tax expense of $31 million between the second quarter of 2006 and the second quarter of 2005 is primarily due to a decrease in pretax book income.

The decrease in income tax expense of $14 million between the six months ended June 30, 2006 and the six months ended June 30, 2005 is 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 ($ in millions)

	June 30, 2006			December 31, 2005		
Long-term Debt, including amounts due within one year	$	12,645	56.7%	$	12,226	57.2%
Short-term Debt		159	0.7		10	0.0
Total Debt		12,804	57.4		12,236	57.2
Common Equity		9,426	42.3		9,088	42.5
Preferred Stock		61	0.3		61	0.3
Total Debt and Equity Capitalization	$	22,291	100.0%	$	21,385	100.0%

The amount of our common equity increased primarily due to earnings exceeding the amount of dividends paid in 2006. However, as a consequence of increasing debt for capital investment during 2006, our ratio of total debt to total capital increased from 57.2% to 57.4%.

The FASB's current pension and postretirement benefit accounting project could have a major negative impact on our debt to capital ratio in future years. The potential change could require the recognition of an additional minimum liability for fully-funded pension and postretirement benefit plans, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 deferral and amortization of net actuarial gains and losses. If adopted, this could require recognition of a significant net-of-tax accumulated other comprehensive income reduction to common equity for those regulatory jurisdictions where a regulatory asset cannot be recorded. The proposed effective date is fiscal years ending after December 15, 2006. We cannot predict the ultimate effects of the final amendment if adopted.

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 June 30, 2006, 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 2010
Revolving Credit Facility		1,500	April 2011
Total		3,000	
Cash and Cash Equivalents		249	
Total Liquidity Sources		3,249	
Less: AEP Commercial Paper Outstanding		144	
Letter of Credit Drawn		31	
Net Available Liquidity	$	3,074	

In April 2006, we amended the terms and increased the size of our credit facilities from $2.7 billion to $3 billion on terms more economically favorable than the previous agreements. The amended facilities are structured as two $1.5 billion credit facilities, each with an option to issue up to $200 million 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 June 30, 2006, this contractually-defined percentage was 54.4%. Nonperformance of these covenants could result in an event of default under these credit agreements. At June 30, 2006, 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 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 amended revolving credit facilities do not contain a material adverse change clause.

Under a regulatory order, our utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts the 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 June 30, 2006, all utility subsidiaries were comfortably in compliance with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At June 30, 2006, our utility subsidiaries had not exceeded those authorized limits.

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2006 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.

Cash Flow

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

	Six Months Ended June 30,			
		2006		**2005**
		(in millions)		
Cash and Cash Equivalents at Beginning of Period	$	401	$	320
Net Cash Flows From Operating Activities		1,137		982
Net Cash Flows From (Used For) Investing Activities		(1,586)		458
Net Cash Flows From (Used For) Financing Activities		297		(1,153)
Net Increase (Decrease) in Cash and Cash Equivalents		(152)		287
Cash and Cash Equivalents at End of Period	$	249	$	607

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 June 30, 2006, we had credit facilities totaling $3.0 billion to support our commercial paper program with $144 million outstanding.

The maximum amount of commercial paper outstanding during the six months ended June 30, 2006 was $325 million. The weighted-average interest rate for our commercial paper during the first six months of 2006 was 4.86%. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are 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

	Six Months Ended June 30,	
	2006	**2005**
	(in millions)	
Net Income	$ 556	$ 576
Less: Income From Discontinued Operations	(6)	(4)
Income From Continuing Operations	550	572
Noncash Items Included in Earnings	634	611
Changes in Assets and Liabilities	(47)	(201)
Net Cash Flows From Operating Activities	$ 1,137	$ 982

The key driver of the increase in cash from operations for the first six months of 2006 was due to no Pension Contributions to Qualified Plan Trusts in 2006 compared with a $204 million contribution in 2005.

Net Cash Flows From Operating Activities were $1.1 billion in 2006 consisting primarily of Income from Continuing Operations of $550 million adjusted for noncash charges of $634 million, which principally includes $689 million for Depreciation and Amortization. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. Under-recovered fuel costs decreased in 2006 due to the 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 $185 million cash increase from net Accounts Receivable/Accounts Payable due to a lower balance of Customer Accounts Receivable at June 30, 2006 and a $189 million decrease in cash related to customer deposits held for trading activities.

Net Cash Flows From Operating Activities were $982 million in 2005 consisting primarily of Income from Continuing Operations of $572 million adjusted for noncash charges of $611 million, which principally includes $652 million for Depreciation and Amortization. We realized gains of $115 million on sales of assets and made contributions of $204 million to our pension trust fund. Changes in Assets and Liabilities represent those 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 $155 million cash increase from Accounts Receivable, Net and an increase in the balance of Accrued Taxes of $172 million. Cash increased related to Accounts Receivable, Net due to a higher factored balance at June 30, 2005. Accrued Taxes increased due to no estimated federal income tax payment during the first quarter of 2005 and paying $43 million, net of refunds received, during the first half of 2005.

Investing Activities

Six Months Ended
June 30,

	2006		2005	
	(in millions)			
Investment Securities:				
Purchases of Investment Securities	$	(5,647)	$	(2,141)
Sales of Investment Securities		5,596		2,213
Change in Investment Securities, Net		(51)		72
Construction Expenditures		(1,625)		(1,020)
Change in Other Temporary Cash Investments, Net		3		(103)
Proceeds from Sales of Assets		123		1,500
Other		(36)		9
Net Cash Flows From (Used for) Investing Activities	$	(1,586)	$	458

Net Cash Flows Used For Investing Activities were $1.6 billion in 2006 primarily due to Construction Expenditures, which increased mostly due to our environmental investment plan.

During 2006, we purchased $5.6 billion of investments and received $5.6 billion of proceeds from the sales of securities. During 2005, we purchased $2.1 billion of investments and received $2.2 billion of proceeds from the sales of securities. In our normal course of business, we purchase auction rate securities and variable rate demand notes with cash available for short-term investments. These amounts also include purchases and sales within our nuclear trusts.

Net Cash Flows From Investing Activities were $458 million in 2005 primarily due to the proceeds from the sale of HPL, a portion of which we used to repurchase common stock and retire senior unsecured notes. Our Construction Expenditures of $1 billion included generation, environmental, transmission and distribution investment.

We forecast $2.1 billion of Construction Expenditures for the remainder of 2006, which will be funded through results of operations and financing activities. These 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, and the ability to access capital.

Financing Activities

	Six Months Ended June 30,			
	2006		2005	
	(in millions)			
Issuance of Common Stock	$	6	$	28
Repurchase of Common Stock		-		(427)
Issuance/Retirement of Debt, Net		552		(389)
Dividends Paid on Common Stock		(291)		(273)
Other		30		(92)
Net Cash Flows From (Used for) Financing Activities	$	297	$	(1,153)

Net Cash Flows From Financing Activities in 2006 were $297 million. During the six months of 2006, we issued $115 million of new obligations relating to pollution control bonds, issued $850 million of notes and retired $396 million of notes for a net increase in notes outstanding of $454 million and increased our short-term commercial paper outstanding by $144 million. See Note 13 for a complete discussion of long-term debt issuances and retirements. The Other amount of $30 million in the above table includes a $68 million payment received from a coal supplier, net of an $8 million repayment, related to a long-term coal purchase contract amended in March 2006.

Net Cash Flows Used For Financing Activities in 2005 were $1.2 billion. During the six months of 2005, we repurchased common stock using a portion of the proceeds from the sale of HPL. In addition, our subsidiaries retired $66 million of cumulative preferred stock, which is reflected in the Other amount in the above table.

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 have changed from year-end as follows:

	June 30, 2006	December 31, 2005
	(in millions)	
AEP Credit	$ 560	$ 516
Rockport Plant Unit 2	2,437	2,511
Railcars	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 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" - "Financing Activities" above.

Other

Cook Plant Outage

On July 30, 2006, Unit 1 of our Cook Plant was taken off line due to elevated ambient temperatures in the containment building caused by a combination of high Lake Michigan water temperatures and partial blockage of cooling ventilation units. The Unit's operating license limits the containment building temperature to 120 degrees. Supplemental cooling units were installed on both units and will remain in place for the near future. Unit 1 returned to service on August 3, 2006.

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. In March of 2006, we received a $70 million payment for our share in earnings for 2005. The payment for 2006 is contingent on Centrica's future operating results, capped at $20 million and, to the extent earned, is expected to be received in the first quarter of 2007. See "Texas REPs" section of Note 8.

New Generation

In December 2005, PSO sought proposals for new base load generation to be online in 2011. PSO received six proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third party. In July 2006, PSO announced plans to enter a joint venture with Oklahoma Gas and Electric Company (OG&E)

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. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion. The 2006 through 2008 estimated construction expenditures as disclosed in our 2005 Form 10-K included cost estimates for a base load facility.

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 short-term, mid-term and long-term generation to meet 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 the existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build a new base load coal or lignite-fueled plant by 2011 to meet the longer-term generation needs of its customers. Preliminary cost estimates for the new facilities are approximately $1.4 billion. The 2006 through 2008 estimated construction expenditures as disclosed in our 2005 Form 10-K included cost estimates for these types of facilities.

All new generation construction projects discussed above are subject to regulatory approvals from the various states in which the companies operate. Construction is expected to begin in 2007.

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 2005 Annual Report. The 2005 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 2005 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition.

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 stretching from West Virginia to New Jersey. The 765 kV line is designed to create a major thoroughfare and reduce PJM congestion costs by substantially improving west-east peak transfer capability by approximately 5,000 MW and reducing transmission line losses by up to 280 MW. It will also enhance reliability of the Eastern transmission grid. A new subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected cost for the project is approximately $3 billion, which may be shared with other participants, and the project is subject to PJM, state and federal regulatory approvals and appropriate incentive cost recovery mechanisms. The projected in-service date is 2014, subject to PJM and FERC approvals, assuming three years to site and acquire rights-of-way and five years to construct the line. We also were the first to file with the DOE seeking to have the proposed route designated 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 July 2006, the FERC granted conditional approval for incentive rate treatment for the proposed line as we requested. The approval is conditioned upon the new line being included in PJM's formal Regional Transmission Expansion Plan to be finalized later this year or in early 2007. The approved incentives include, (a) a return on equity set at the high end of the "zone of reasonableness"; (b) the option to timely recover the cost of capital associated with construction work in progress; and (c) the ability to defer expense and recover costs incurred during the pre-construction and pre-operating period. The approval does not constitute final FERC action, as we will need to implement the incentives in future rate filings.

Texas Regulatory Activity

Texas Restructuring

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was $1.475 billion including carrying costs through September 2005. In December 2005, TCC adjusted its recorded net true-up regulatory asset to comply with the order. We appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties have appealed the PUCT's order claiming it permits TCC to over-recover stranded costs.

TCC filed an application in March 2006 requesting to securitize its net stranded generation plant costs and related carrying costs through August 31, 2006. In June 2006, the PUCT approved TCC's settlement with intervenors authorizing the securitization of $1.697 billion of net stranded generation costs including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of $23 million, for a total of $1.72 billion. We anticipate issuing the securitization bonds by the end of the third quarter of 2006.

The differences between the securitization amount ordered by the PUCT of $1.7 billion and the recorded securitizable true-up regulatory asset of $1.5 billion at June 30, 2006 are detailed in the table below:

		(in millions)
Stranded Generation Plant Costs	$	974
Net Generation-related Regulatory Asset		249
Excess Earnings		(49)
Recorded Net Stranded Generation Plant Costs		1,174
Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs		375
Recorded Securitizable True-up Regulatory Asset		1,549
Unrecorded But Recoverable Equity Carrying Costs		217
Unrecorded Estimated July 2006 - August 2006 Debt Carrying Costs		17
Unrecorded Excess Earnings, Related Carrying Costs and Other		52
Settlement Reduction		(77)
Reduction for ADITC and EDFIT Benefits		(61)
Approved Securitizable Amount		1,697
Unrecorded Securitization Issuance Costs		23
Amount to be Securitized	$	1,720

In June 2006, TCC filed to implement a CTC refund of $355 million for its net other true-up items over eight years. The differences between the components of TCC's Recorded Net Regulatory Liabilities for Other True-up Items as of June 30, 2006 and its CTC proceeding request are detailed below**:**

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		28
Retail Clawback including Carrying Costs		(63)
Deferred Over-recovered Fuel Balance		(181)
Retrospective ADFIT Benefit		(70)
Other		(4)
Recorded Net Regulatory Liabilities - Other True-up Items		(229)
Unrecorded Prospective ADFIT Benefit		(240)
Unrecorded Estimated July 2006 - August 2006 Carrying Costs		(6)
Gross CTC Refund		(475)
FERC Jurisdictional Fuel Refund Deferral		16
ADITC and EDFIT Benefit Refund Deferral		97
Net CTC Refund Proposed, After Deferrals		(362)
Rate Case Expense Surcharge		7

Net Refund Proposed, After Deferrals and Expenses	$	(355)

TCC requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of $16 million of FERC jurisdictional fuel over-recoveries and $97 million for potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits. Although TCC proposed to refund the $355 million over eight years, certain intervenors have supported accelerated refunds. Management cannot predict the outcome of this filing. If the two contingent federal matters are resolved unfavorably, TCC will refund the $16 million and the $97 million plus carrying costs.

Municipal customers and other intervenors are appealing the PUCT orders seeking to further reduce TCC's true-up recoveries. If we determine as a result of future PUCT orders or appeal court rulings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC is appealing the PUCT orders seeking relief in both state and federal court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

These appeals could take years to resolve and could result in material effects on future results of operations. If the PUCT rejects TCC's deferral proposal and a normalization violation occurs, future results of operations and cash flows could be adversely affected by the recapture of $105 million of TCC's ADITC and the loss by TCC of future accelerated tax depreciation election. The estimated future impact on earnings of the Texas restructuring as of June 30, 2006, exclusive of a possible normalization violation and any effects of appeal litigation, over the 14-year securitization net recovery period assuming the PUCT approves TCC's CTC filing is detailed below:

		(in millions)
ADITC and EDFIT Benefits Reducing Securitization	$	97
ADFIT Benefit Applied to Reduce 2002 Securitization of Regulatory Assets		(64)
Securitization Settlement		(77)
Unrecorded Prospective ADFIT Benefit Increasing the CTC Refund		(240)
Unrecorded Equity Carrying Costs Recognized as Collected		217
Future Carrying Cost Payable on Proposed CTC Refund		(113)
Deferred Fuel - Federal Jurisdictional Issue		16
Net Adverse Earnings Impact Over 14 Years	$	(164)

If the proposed CTC deferral is rejected by the PUCT or the two contingencies are refunded to customers, the future adverse impact on results of operations over the next 14 years will increase to $317 million. This potential adverse impact on results of operations over the next 14 years would be more than offset by the annual cost of money benefit from the $2.2 billion in net proceeds that resulted from the sale of bonds in connection with the initial regulatory asset securitization in 2002 of $797 million and from the upcoming $1.720 billion sale of securitization bonds later this year less the proposed $355 million CTC refund over the next eight years.

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 our pending litigation and regulatory proceedings see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring, Note 7 - Commitments and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of

Results of Operations" in the 2005 Annual Report. Additionally, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies included herein. An adverse result in these proceedings has 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 have committed to substantial capital investments and additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the CAA to reduce emissions of SO_2, NO_x, particulate matter (PM), and mercury from fossil fuel-fired power plants;
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain of our power plants; and
- Possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change.

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. All of these matters are discussed in the "Environmental Matters" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2005 Annual Report.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra margin for safety. These concentration levels are known as national ambient air quality standards (NAAQS).

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must then develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are then submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA must develop and implement a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO_2 and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO_2 and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70 percent from current levels by 2015. Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. The Federal EPA affirmed certain aspects of the final CAIR after considering petitions for reconsideration. The rule has been challenged in the courts. States must develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which our power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x emissions in order to comply with CAIR. The Federal EPA reaffirmed the final CAMR after reconsidering certain aspects of the rule, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA included a cap-and-trade emission reduction program for SO_2 emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NO_x emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. We meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels, and participation in the emissions allowance markets. CAIR uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and trade system.

Regional Haze: The CAA also establishes visibility goals for certain federally-designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment and remedying any existing impairment of visibility in these areas. This is commonly called the “Regional Haze” program. In June 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA’s best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration that for power plants subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x, some additional controls will be required. The final rule has been challenged in the courts.

Estimated Air Quality Environmental Investments

As discussed in the 2005 Annual Report, the CAIR and CAMR programs described above will require us to make significant additional investments, some of which are estimable. However, many of the rules described above have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Our 2006 through 2010 investment estimates of $191 million for NO_x controls and $2.8 billion for SO_2 controls disclosed in the 2005 Annual Report are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation, required levels of reductions, methods for allocation of allowances and our selected compliance alternatives. In short, we cannot estimate our compliance costs with certainty.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Potential Regulation of CO_2 Emissions

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol in November 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Several bills have been introduced in Congress seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none have passed either house of Congress.

The Federal EPA stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. This decision was challenged in the courts and upheld by an appellate court. The U.S. Supreme Court will review the appellate decision. While mandatory requirements to reduce CO_2 emissions at our power plants do not appear imminent, we participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

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, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain environmental intervenor groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and 2000 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. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 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. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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 one 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 Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that would exclude most of the challenged activities from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability 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 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.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, we manage other environmental concerns that we do not believe are material or potentially material at this time. If they become significant or if any new matters arise that we believe could be material, they could have a material adverse effect on 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 2005 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

Beginning in 2006, we adopted SFAS No. 123 (revised 2004) Share-Based Payment, on a modified prospective basis, resulting in an insignificant favorable cumulative effect of a change in accounting principle. Including stock-based compensation expense related to employee stock options and other share based awards, did not materially affect our quarter-over-quarter and year-to-date net income and earnings per share. As of June 30, 2006, we have $43 million of total unrecognized compensation cost related to unvested share-based compensation arrangements. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.63 years. See Note 2 - New Accounting Pronouncements in our Condensed Notes to Condensed Consolidated Financial Statements for further discussion.

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 in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Investment - Gas Operations segment 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.

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 controlled by risk management operations, our Chief Risk Officer and risk management staff. When risk management activities exceed certain predetermined limits, the positions are modified to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

We have policies and procedures that allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, senior executives, and other senior financial and operating managers.

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 is composed of the chief risk officers of major electricity and gas companies in the United States. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. Implementation of the disclosures is voluntary. We support the work of the CCRO and have embraced 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 in our condensed balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value included in our condensed balance sheet as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
June 30, 2006
(in millions)

Total

	Utility Operations	Investments - Gas Operations	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	
Current Assets	$ 431	$ 123	$ 554	$ 65	$ 619
Noncurrent Assets	390	175	565	12	577
Total Assets	821	298	1,119	77	1,196
Current Liabilities	(338)	(126)	(464)	(16)	(480)
Noncurrent Liabilities	(235)	(181)	(416)	(2)	(418)
Total Liabilities	(573)	(307)	(880)	(18)	(898)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 248	$ (9)	$ 239	$ 59	$ 298

MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2006
(in millions)

	Utility Operations	Investments-Gas Operations	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2005	$ 215	$ (19)	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(8)	8	-
Fair Value of New Contracts at Inception When Entered During the Period (a)	1	-	1
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	13	-	13
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	1	-	1
Changes in Fair Value due to Market Fluctuations During the Period (b)	13	2	15
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	13	-	13
Total MTM Risk Management Contract Net Assets (Liabilities) at June 30, 2006	$ 248	$ (9)	239
Net Cash Flow and Fair Value Hedge Contracts			59
Ending Net Risk Management Assets at June 30, 2006			$ 298

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek 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 in the Condensed Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions. Approximately $7 million of the regulatory deferral change is due to the change in the SIA. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

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, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of June 30, 2006
(in millions)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ (11)	$ 1	$ 14	$ -	$ -	$ -	$ 4
Prices Provided by Other External Sources - OTC Broker Quotes (a)	43	68	33	25	-	-	169
Prices Based on Models and Other Valuation Methods (b)	20	(1)	6	13	28	9	75
Total	$ 52	$ 68	$ 53	$ 38	$ 28	$ 9	$ 248
Investments - Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ (1)	$ 11	$ -	$ -	$ -	$ -	$ 10
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(3)	(8)	-	-	-	-	(11)
Prices Based on Models and Other Valuation Methods (b)	(1)	-	(1)	(4)	(3)	1	(8)
Total	$ (5)	$ 3	$ (1)	$ (4)	$ (3)	$ 1	$ (9)
Total:							
Prices Actively Quoted - Exchange Traded Contracts	$ (12)	$ 12	$ 14	$ -	$ -	$ -	$ 14
Prices Provided by Other External Sources - OTC Broker Quotes (a)	40	60	33	25	-	-	158
Prices Based on Models and Other Valuation Methods (b)	19	(1)	5	9	25	10	67
Total	$ 47	$ 71	$ 52	$ 34	$ 25	$ 10	$ 239

(a)

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

(b) Prices Based on Models and Other Valuation Methods is 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 June 30, 2006

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	21
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	21
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East	42
	Physical Forwards	AEP West	42
	Physical Forwards	West Coast	42
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	30
Coal	Physical Forwards	PRB, NYMEX, CSX	30

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 and remaining gas operations. We monitor these risks on our future operations and may employ various commodity instruments and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of 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.

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, 2005 to June 30, 2006. 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 effective 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 are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Six Months Ended June 30, 2006
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance in AOCI, December 31, 2005	$ (6)	$ (21)	$ (27)
Changes in Fair Value	37	12	49
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	3	2	5
Ending Balance in AOCI, June 30, 2006	$ 34	$ (7)	$ 27
After-Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 30	$ (1)	$ 29

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of June 30, 2006, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 5.90%, expressed in terms of net MTM assets and net receivables. As of June 30, 2006, 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%	Net Exposure of Counterparties >10%
Investment Grade	$ 883	$ 156	$ 727	1	$ 107
Split Rating	2	-	2	2	2
Noninvestment Grade	109	106	3	1	3
No External Ratings:					
Internal Investment Grade	28	-	28	1	10
Internal Noninvestment Grade	58	13	45	3	43
Total as of June 30, 2006	$ 1,080	$ 275	$ 805	8	$ 165
As of December 31, 2005	$ 1,366	$ 484	$ 882	10	322

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, 2008. This table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of June 30, 2006

	Remainder 2006	2007	2008
Estimated Plant Output Hedged	91%	90%	88%

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 June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

Six Months Ended June 30, 2006 (in millions)				Twelve Months Ended December 31, 2005 (in millions)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$2	$7	$3	$1	$3	$5	$3	$1

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 $690 million at June 30, 2006 and $615 million at December 31, 2005. 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 OPERATIONS
For the Three and Six Months Ended June 30, 2006 and 2005
(in millions, except per-share amounts)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2006	**2005**	**2006**	**2005**
REVENUES				
Utility Operations	$ 2,810	$ 2,680	$ 5,797	$ 5,285
Gas Operations	(15)	19	(33)	376
Other	141	120	280	223
TOTAL	2,936	2,819	6,044	5,884
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	888	804	1,849	1,593
Purchased Energy for Resale	237	183	403	313
Purchased Gas for Resale	-	1	-	250
Maintenance and Other Operation	902	878	1,730	1,715
Gain/Loss on Disposition of Assets, Net	-	-	(68)	(115)
Depreciation and Amortization	348	325	689	652
Taxes Other Than Income Taxes	190	173	381	361
TOTAL	2,565	2,364	4,984	4,769
OPERATING INCOME	371	455	1,060	1,115
Interest and Investment Income	11	14	19	25
Carrying Costs Income	33	36	63	56
Allowance For Equity Funds Used During Construction	7	6	13	12
Gain on Disposition of Equity Investments, Net	-	-	3	-
INTEREST AND OTHER CHARGES				
Interest Expense	176	188	344	361
Preferred Stock Dividend Requirements of Subsidiaries	-	3	1	5
TOTAL	176	191	345	366
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS (LOSS)	246	320	813	842
Income Tax Expense	72	103	261	275
Minority Interest Expense	1	1	1	2
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(1)	2	(1)	7

INCOME BEFORE DISCONTINUED OPERATIONS		172		218		550		572
DISCONTINUED OPERATIONS, Net of Tax		3		3		6		4
NET INCOME	$	175	$	221	$	556	$	576
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		394		384		394		389
BASIC EARNINGS PER SHARE								
Income Before Discontinued Operations	$	0.44	$	0.57	$	1.40	$	1.47
Discontinued Operations, Net of Tax		-		0.01		0.01		0.01
TOTAL BASIC EARNINGS PER SHARE	$	0.44	$	0.58	$	1.41	$	1.48
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		396		385		396		390
DILUTED EARNINGS PER SHARE								
Income Before Discontinued Operations	$	0.43	$	0.57	$	1.39	$	1.47
Discontinued Operations, Net of Tax		0.01		0.01		0.02		0.01
TOTAL DILUTED EARNINGS PER SHARE	$	0.44	$	0.58	$	1.41	$	1.48
CASH DIVIDENDS PAID PER SHARE	$	0.37	$	0.35	$	0.74	$	0.70

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2006 and December 31, 2005
(in millions)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 249	$ 401
Other Temporary Cash Investments	173	127
Accounts Receivable:		
Customers	659	826
Accrued Unbilled Revenues	347	374
Miscellaneous	45	51
Allowance for Uncollectible Accounts	(34)	(31)
Total Receivables	1,017	1,220
Fuel, Materials and Supplies	865	726
Risk Management Assets	619	926
Margin Deposits	154	221
Regulatory Asset for Under-Recovered Fuel Costs	74	197
Other	104	127
TOTAL	3,255	3,945
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,877	16,653
Transmission	6,915	6,433
Distribution	11,073	10,702
Other (including coal mining and nuclear fuel)	3,203	3,116
Construction Work in Progress	2,423	2,217
Total	40,491	39,121
Accumulated Depreciation and Amortization	15,093	14,837
TOTAL - NET	25,398	24,284
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,234	3,262
Securitized Transition Assets and Other	572	593
Spent Nuclear Fuel and Decommissioning Trusts	1,159	1,134
Investments in Power and Distribution Projects	45	97
Goodwill	76	76
Long-term Risk Management Assets	577	886
Employee Benefits and Pension Assets	1,075	1,105
Other	747	746
TOTAL	7,485	7,899
Assets Held for Sale	46	44
TOTAL ASSETS	$ 36,184	$ 36,172

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

		2006		**2005**
CURRENT LIABILITIES		**(in millions)**		
Accounts Payable	$	1,191	$	1,144
Short-term Debt		159		10
Long-term Debt Due Within One Year		800		1,153
Risk Management Liabilities		480		906
Accrued Taxes		742		651
Accrued Interest		183		183
Customer Deposits		382		571
Other		624		842
TOTAL		4,561		5,460
NONCURRENT LIABILITIES				
Long-term Debt		11,845		11,073
Long-term Risk Management Liabilities		418		723
Deferred Income Taxes		4,792		4,810
Regulatory Liabilities and Deferred Investment Tax Credits		2,819		2,747
Asset Retirement Obligations		962		936
Employee Benefits and Pension Obligations		339		355
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2		152		157
Deferred Credits and Other		809		762
TOTAL		22,136		21,563
TOTAL LIABILITIES		26,697		27,023
Cumulative Preferred Stock Not Subject to Mandatory Redemption		61		61
Commitments and Contingencies (Note 5)				
COMMON SHAREHOLDERS' EQUITY				
Common Stock Par Value $6.50:				

	2006	2005				
Shares Authorized	600,000,000	600,000,000				
Shares Issued	415,446,501	415,218,830				
(21,499,992 shares were held in treasury at June 30, 2006 and December 31, 2005)				2,700		2,699
Paid-in Capital				4,138		4,131
Retained Earnings				2,550		2,285
Accumulated Other Comprehensive Income (Loss)				38		(27)
TOTAL				9,426		9,088
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY			$	36,184	$	36,172

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in millions)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 556	$ 576
Less: Income from Discontinued Operations	(6)	(4)
Income from Continuing Operations	550	572
Adjustments for Noncash Items:		
Depreciation and Amortization	689	652
Accretion of Asset Retirement Obligations	30	35
Deferred Income Taxes	10	(75)
Deferred Investment Tax Credits	(14)	(15)
Carrying Costs Income	(63)	(56)
Mark-to-Market of Risk Management Contracts	(43)	43
Amortization of Nuclear Fuel	25	27
Deferred Property Taxes	12	10
Pension Contributions to Qualified Plan Trusts	-	(204)
Fuel Over/Under-Recovery, Net	128	(45)
Gain on Sales of Assets and Equity Investments, Net	(71)	(115)
Change in Other Noncurrent Assets	109	(59)
Change in Other Noncurrent Liabilities	(42)	(83)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	202	155
Fuel, Materials and Supplies	(140)	(29)
Accounts Payable	(17)	63
Accrued Taxes	90	172
Customer Deposits	(189)	(34)
Other Current Assets	86	63
Other Current Liabilities	(215)	(95)
Net Cash Flows From Operating Activities	1,137	982
INVESTING ACTIVITIES		
Construction Expenditures	(1,625)	(1,020)
Change in Other Temporary Cash Investments, Net	3	(103)
Purchases of Investment Securities	(5,647)	(2,141)
Sales of Investment Securities	5,596	2,213
Proceeds from Sales of Assets	123	1,500
Other	(36)	9
Net Cash Flows From (Used For) Investing Activities	(1,586)	458
FINANCING ACTIVITIES		
Issuance of Common Stock	6	28
Repurchase of Common Stock	-	(427)
Change in Short-term Debt, Net	147	(9)
Issuance of Long-term Debt	1,081	1,660

Retirement of Long-term Debt		(676)		(2,040)
Dividends Paid on Common Stock		(291)		(273)
Other		30		(92)
Net Cash Flows From (Used For) Financing Activities		297		(1,153)
Net Increase (Decrease) in Cash and Cash Equivalents		(152)		287
Cash and Cash Equivalents at Beginning of Period		401		320
Cash and Cash Equivalents at End of Period	$	249	$	607
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	316	$	322
Cash Paid for Income Taxes, Net of Refunds		123		86
Noncash Acquisitions Under Capital Leases		37		22
Construction Expenditures Included in Accounts Payable at June 30,		273		123
Acquisition of Nuclear Fuel in Accounts Payable at June 30,		26		-
Disposition of Liabilities Related to Divestitures		-		22

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND
COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in millions)
(Unaudited)

	Common Stock				Accumulated Other Comprehensive Income (Loss)	
	Shares	Amount	Paid-in Capital	Retained Earnings		Total
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	$ 8,515
Issuance of Common Stock	1	6	22			28
Common Stock Dividends				(273)		(273)
Repurchase of Common Stock			(427)			(427)
Other			15			15
TOTAL						7,858
COMPREHENSIVE INCOME						
Other Comprehensive Loss, Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(1)	(1)
Cash Flow Hedges, Net of Tax of $28					(51)	(51)
NET INCOME				576		576
TOTAL COMPREHENSIVE INCOME						524
JUNE 30, 2005	406	$ 2,638	$ 3,813	$ 2,327	$ (396)	$ 8,382
DECEMBER 31, 2005	415	$ 2,699	$ 4,131	$ 2,285	$ (27)	$ 9,088
Issuance of Common Stock		1	5			6
Common Stock Dividends				(291)		(291)
Other			2			2
TOTAL						8,805
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Cash Flow Hedges, Net of Tax of $29					54	54
Securities Available for Sale, Net of Tax of $6					11	11
NET INCOME				556		556
TOTAL COMPREHENSIVE INCOME						621
JUNE 30, 2006	415	$ 2,700	$ 4,138	$ 2,550	$ 38	$ 9,426

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER, 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 interim financial statements should be read in conjunction with the 2005 Annual Report as incorporated in and filed with our 2005 Form 10-K.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments that are necessary for a fair presentation of our results of operations for interim periods.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on our Condensed Consolidated Balance Sheets in the common shareholders' equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	June 30, 2006	December 31, 2005
	(in millions)	
Securities Available for Sale, Net of Tax	$ 30	$ 19
Cash Flow Hedges, Net of Tax	27	(27)
Minimum Pension Liability, Net of Tax	(19)	(19)
Total	$ 38	$ (27)

At June 30, 2006, we expect to reclassify approximately $29 million of net gains from cash flow hedges in Accumulated Other Comprehensive Income (Loss) to Net Income during the next twelve months at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ as a result of market fluctuations. Forty-two months is the maximum length of time that we hedge our exposure to variability in future cash flows with contracts designated as cash flow hedges.

Stock-Based Compensation Plans

At June 30, 2006, we have options outstanding under two stock-based employee compensation plans: The Amended and Restated American Electric Power System Long-Term Incentive Plan and the Central and South West Corporation Long-Term Incentive Plan. We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees.

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS 123R) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including stock options and employee stock purchases based on estimated fair values. See the SFAS 123 (revised 2004) "Share-Based Payment" section of Note 2 for additional discussion.

In conjunction with the adoption of SFAS 123R, we changed our method of attributing the value of stock-based compensation to expense from the accelerated multiple-option approach to the straight-line single-option method. Compensation expense for all share-based payment awards granted prior to January 1, 2006 will continue to be recognized using the accelerated multiple-option approach while compensation expense for all share-based payment awards granted on or after January 1, 2006 is recognized using the straight-line single-option method. As stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the three and six months periods ended June 30, 2006 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. In our pro forma information presented below as required under SFAS 123 for the periods prior to 2006, we accounted for forfeitures as they occurred.

For the three and six months ended June 30, 2005, no stock option expense was reflected in Net Income as we accounted for stock options using the intrinsic value method under Accounting Principles Board (APB) Opinion No. 25, "Accounting For Stock Issued to Employees." Under the intrinsic value method, no stock option expense is recognized when the exercise price of the stock options granted equals the fair value of the underlying stock at the date of grant. No options were granted during the first six months of 2005. For the three and six months ended June 30, 2006 and 2005, compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units. See Note 10 for additional discussion.

Pro Forma Information Under SFAS 123, "Accounting for Stock-Based Compensation," for Periods Presented Prior to January 1, 2006

The following table shows the effect on our Net Income and Earnings Per Share as if we had applied fair value measurement and recognition provisions of SFAS 123 to stock-based employee and director compensation awards for the three and six months ended June 30, 2005:

		Three Months Ended		Six Months Ended
		(in millions, except per share data)		
Net Income, as reported	$	221	$	576
Add: Stock-based compensation expense included in reported Net Income, net of related tax effects		4		6
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects		(4)		(6)
Pro Forma Net Income	$	221	$	576
Earnings Per Share:				
Basic - as Reported	$	0.58	$	1.48
Basic - Pro Forma (a)	$	0.58	$	1.48
Diluted - as Reported	$	0.58	$	1.48
Diluted - Pro Forma (a)	$	0.58	$	1.48

(a) The pro forma amounts are not representative of the effects on reported net income for future years.

Earnings Per Share (EPS)

The following table presents our basic and diluted Earnings Per Share (EPS) calculations included in our Condensed Consolidated Statements of Operations:

	Three Months Ended June 30,	
	2006	2005

	(in millions, except per share data)							
				$/share				$/share
Earnings applicable to common stock	$	175			$	221		
Average number of basic shares outstanding		393.7	$	0.44		384.2	$	0.58
Average dilutive effect of:								
Performance Share Units		1.4		-		0.8		-
Stock Options		0.2		-		0.3		-
Restricted Stock Units		0.1		-		0.1		-
Restricted Shares		0.1		-		-		-
Average number of diluted shares outstanding		395.5	$	0.44		385.4	$	0.58

	Six Months Ended June 30,							
	2006				2005			
	(in millions, except per share data)							
				$/share				$/share
Earnings applicable to common stock	$	556			$	576		
Average number of basic shares outstanding		393.7	$	1.41		388.6	$	1.48
Average dilutive effect of:								
Performance Share Units		1.4		-		0.8		-
Stock Options		0.2		-		0.3		-
Restricted Stock Units		0.1		-		0.1		-
Restricted Shares		0.1		-		-		-
Average number of diluted shares outstanding		395.5	$	1.41		389.8	$	1.48

Our stock option and other equity compensation plans are discussed in Note 10.

Related Party Transactions

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(in millions)		(in millions)	
AEP Consolidated Purchased Energy:				
Ohio Valley Electric Corporation (43.47% Owned)	$ 58	$ 48	$ 113	$ 91
Sweeny Cogeneration Limited Partnership (50% Owned)	28	31	62	60
AEP Consolidated Other Revenues - Barging and Other Transportation Services - Ohio Valley Electric Corporation (43.47% Owned)	8	4	15	8

Reclassifications

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

On our Condensed Consolidated Statements of Cash Flows, we included purchases and sales of investments within our Spent Nuclear Fuel and Decommissioning Trusts as a component of Investing Activities rather than Operating Activities.

These revisions had no impact on our previously reported results of operations, financial condition 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 2006 that we have determined relate to our operations.

SFAS 123 (revised 2004) "Share-Based Payment"

In December 2004, the FASB issued SFAS 123R. SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under APB Opinion No. 25, "Accounting for Stock Issued to Employees." We recorded an insignificant cumulative effect of a change in accounting principle in the first quarter of 2006 for the effect of initially applying the statement primarily reflected in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards granted after the time of adoption and recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Stock-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2006 includes compensation expense for share-based payment awards granted prior to, but not yet vested as of, January 1, 2006 based on the grant date fair value estimated in accordance with the pro forma provisions of SFAS 123 and compensation expense for the share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS 123R. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

EITF Issue 06-3 "How Taxes Collected from Customers and Remitted to Governmental Authorities Should* Be *Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF 06-3)

In June 2006, the EITF reached a consensus on the income statement presentation of various types of taxes. The scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes. The presentation of taxes within the scope of this issue on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22, “Disclosure of Accounting Policies.” The EITF’s decision on gross/net presentation requires that any such taxes reported on a gross basis be disclosed on an aggregate basis in interim and annual financial statements, for each period for which an income statement is presented, if those amounts are significant.

EITF 06-3 is effective for fiscal years beginning after December 15, 2006. We have not completed the process of determining the effect of this interpretation on our financial statements.

FASB Interpretation No. 48 “Accounting for Uncertainty in Income Taxes” (FIN 48)

In July 2006, the FASB issued FIN 48 which clarifies the application of SFAS 109, “Accounting for Income Taxes.” 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. FIN 48 is effective for fiscal years beginning after December 15, 2006. We have not completed the process of determining the effect of this interpretation on our financial statements.

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 fair value measurements, business combinations, revenue recognition, pension and postretirement benefit plans, liabilities and equity, 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 2005 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and state commissions. The Rate Matters note within our 2005 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 and cash flows. Rate matters that are not believed to be reasonably likely to affect future results of operations and cash flows are not included in this report or the 2005 Annual Report. The following sections discuss ratemaking developments in 2006 updating the 2005 Annual Report.

APCo Virginia Environmental and Reliability Costs

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. In 2005, APCo filed a request with the Virginia SCC and updated it through supplemental testimony seeking recovery of $21 million of incremental E&R costs incurred from July 2004 through September 2005. Through June 30, 2006, APCo deferred $37 million of incurred incremental E&R costs.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to increase its electric rates at an ongoing level of $20 million to recover current, rather than past, incremental E&R costs. The staff proposal would effectively disallow the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that were deferred as a regulatory asset. At the E&R hearings, which concluded in March 2006, the staff amended its testimony to recommend a $24 million increase in APCo's ongoing rates. We believe the staff's proposal is contrary to the statute and an October 2005 Virginia SCC order, which denied APCo's original request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incremental E&R costs that the commission finds prudent.

If the Virginia SCC properly implements the statute and its related October 2005 order, not withstanding use of estimates, we should be able to recover all of our prudently incurred E&R costs. However, if the Virginia SCC reverses its position and adopts the staff's recommendations or denies recovery of any of APCo's deferred E&R costs, future results of operations and cash flows would be adversely impacted.

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 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 adjusted annually. APCo also proposed to share the off-system sales margins with the customers. This proposed off-system sales fuel rate credit of $27 million partially offsets the $225 million requested increase in base rates for a net increase in revenues of $198 million. The major components of the $225 million rate request include $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million due to projected net 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 full requested base rate increase of $225 million into effect October 2, 2006, subject to refund. Hearings are scheduled to begin in December 2006. We are unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

APCo and WPCo West Virginia Rate Case

In July 2006, the WVPSC approved the settlement agreement APCo and WPCo reached with the WVPSC staff and intervenors in the West Virginia rate case filed in 2005. The settlement agreement provided for an initial overall increase in rates of $44 million effective July 28, 2006 comprised of:

- A $56 million increase in Expanded Net Energy Cost (ENEC) for fuel and purchased power expenses;
- A $23 million special construction surcharge providing recovery of the costs of scrubbers and the Wyoming-Jacksons Ferry 765 kV line to date;
- An $18 million general base rate reduction based on a return on equity of 10.5%, of which $9 million relates to a reduction in depreciation expense which affects cash flows but not earnings; and
- A $17 million credit to refund a portion of deferred prior over-recoveries of ENEC costs of $51 million, currently recorded in regulatory liabilities on the Condensed Consolidated Balance Sheets. Therefore, this item impacts cash flows but has no effect on earnings.

In addition, the agreement provides a surcharge mechanism that allows APCo and WPCo to adjust their rates annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments in scrubbers at APCo's Mountaineer and John Amos power plants and the costs of the Wyoming-Jacksons Ferry line. Although the amount of these annual surcharge increases cannot be determined until the incremental costs are known and reviewed by the WVPSC, APCo estimates that they will result in an annual increase in revenues of $36 million effective July 1, 2007, $14 million effective July 1, 2008 and $18 million effective July 1, 2009.

The settlement further provides for the reinstatement of the ENEC mechanism effective July 1, 2006 with over/under recovery deferral accounting and annual ENEC proceedings to affect annual rate adjustments for changes in fuel and purchased power costs beginning in 2007. The settlement provides for the return to customers of the remaining portion of the prior ENEC regulatory liability including interest at a LIBOR rate on the unrefunded balance in future ENEC proceedings.

I&M Depreciation Study Filing

In December 2005, I&M filed a petition with the IURC seeking authorization to revise its book depreciation rates applicable to its electric utility plant in service effective January 1, 2006. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis 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 is not a request for a change in customers' electric service rates. Intervenors filed testimony in March 2006 arguing that the book depreciation rates should not be revised until the Indiana rate cap ends in July 2007 or until base rates are revised. I&M filed its rebuttal testimony in April 2006. A public hearing was held in May 2006 and the final brief was filed in June 2006. As proposed by I&M, the book depreciation expense reduction would increase earnings, but would not impact cash flows until electric service rates are revised. If approved by the IURC, I&M will currently reduce its book depreciation expense from the approved effective date forward. We are awaiting the IURC order.

KPCo Environmental Surcharge Filing

In June 2006, KPCo filed a notice of its intent to file an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge on or after August 16, 2006.

KPCo Rate Filing

In March 2006, the KPSC approved the settlement agreement in KPCo's 2005 base rate case. The approved agreement provides for a $41 million annual increase in revenues effective March 30, 2006 and the retention of the existing environmental surcharge tariff. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and AFUDC.

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 18 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 through 2003 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 their 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 has been refunded, thus removing that issue from their 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. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC 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.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals and will defend its position vigorously. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs or offsets under-recovered fuel deferrals with additional reallocated off-system sales margins, our future results of operations and cash flows could be adversely affected. However, if the position taken by the federal court in Texas applies to PSO's case, the OCC could 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 may file a complaint at the FERC alleging the allocation of off-system sales margins adopted by 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. To date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect, if any, of these Oklahoma fuel clause proceedings and any future FERC proceedings on future results of operations, cash flows and financial condition.

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. Both the OCC staff and Attorney General of Oklahoma filed testimony, finding no disallowances in the test year data. 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 existed during the year. A hearing is scheduled for August 2006.

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 biennial reviews. The OCC staff indicated that it expects the review process to begin in the fourth quarter of 2006.

Management cannot predict the outcome of this review 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.

SWEPCo Louisiana Fuel Inquiry

In March 2006, the Louisiana Public Service Commission (LPSC) closed its inquiry into SWEPCo's fuel and purchased power procurement activities during the period January 1, 2005 through October 31, 2005. The LPSC approved the LPSC staff's report, which concluded that SWEPCo's activities were appropriate and did not identify any disallowances or areas for improvement.

SWEPCo PUCT Staff Review of Earnings

In October 2005, the staff of the PUCT reported the results of its review of SWEPCo's year-end 2004 earnings. Based on the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff engaged SWEPCo in discussions to reconcile the earnings calculation and to consider possible ways to address the results. After those discussions, the PUCT staff informed SWEPCo in April 2006 that they would not pursue the matter further.

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. In April 2004, at the request of the LPSC, SWEPCo filed updated financial information with a test year ending December 31, 2003. Both filings indicated that SWEPCo’s rates should not be reduced. Subsequently, direct testimony was filed by the LPSC staff's consultants recommending a $15 million reduction in SWEPCo’s Louisiana jurisdictional base rates based on an 8.95% return on equity and the disallowance of projected increased pension expense. 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%. 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, which included a 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain ongoing operations and maintenance expense levels and the recommended base rate reduction does not include the impact of a proposed consolidated federal income tax adjustment, which would increase the proposed rate reduction. SWEPCo intends to file rebuttal testimony refuting the consultant's recommendations. Hearings are scheduled for October 2006. A decision is not expected until late 2006 at the earliest. 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 and cash flows.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT’s December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC’s and TNC’s former affiliated REPs, respectively). In June 2003, the District Court ruled the PUCT record lacked substantial evidence regarding the effect of loss of load due to retail competition on the generation requirements of both Mutual Energy WTU and Mutual Energy CPL and on the PTB rates. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court. The cities appealed the appeals court decision to the Texas Supreme Court. Management cannot predict the outcome of further appeals, but a reversal of the favorable court of appeals decision regarding the loss of load issue could result in the issue being returned to the PUCT for further consideration. If the PUCT were to reverse its decision and order refunds of PTB revenues, it could adversely impact results of operations and cash flows.

RTO Formation/Integration Costs

In 2005, the FERC approved the amortization of approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs over 10 years. Total amortization related to such costs was $1 million in both the second quarter of 2006 and 2005. In the first half of both 2006 and 2005, total amortization related to such costs was $2 million. As of June 30, 2006 and December 31, 2005, the AEP East companies had $30 million and $31 million, respectively, of deferred unamortized RTO and PJM formation/integration costs.

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM AEP zone OATT to recover the amortization of deferred RTO formation/integration costs not billed by PJM of $2 million per year. The AEP East companies will be responsible for paying the majority of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In May 2006, the FERC approved a settlement that provides for recovery over a ten-year period of 41% of our deferred PJM-billed and incurred integration costs and related carrying charges from the PJM region outside of the AEP zone and the remaining 59% from within the AEP zone. As a result, the AEP East companies are responsible for paying approximately 50% of the amortized PJM-billed integration costs (59% of costs to be recovered within the AEP zone times 85% internal load factor within the AEP zone) for their internal load usage of the transmission system.

CSPCo, OPCo and KPCo are recovering the amortization of RTO formation/integration costs billed to our AEP East companies in Ohio and Kentucky. APCo received approval to include the amortization of RTO formation/integration costs in retail rates in West Virginia effective July 28, 2006. In Virginia, APCo recently filed a base rate case which includes recovery of these costs. In Indiana, I&M is subject to a rate cap until June 30, 2007.

Until APCo and I&M can adjust their retail rates to recover the amortization of their RTO-related deferred costs, results of operations and cash flows will be adversely affected by approximately one-third of the amortizations. APCo will recover its RTO amortizations starting in late July 2006 in West Virginia and is scheduled to commence recovery in early October 2006 in Virginia. The new Virginia rates will be subject to refund. If the Virginia or Indiana commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs, it would result in a write-off of up to one-third of the total remaining deferred balance and thereby, adversely impact future results of operations and cash flows.

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

In accordance with FERC orders, we collected SECA rates to mitigate lost through-and-out transmission service (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 indicated that the SECA rate revenues are collected subject to refund or surcharge. The AEP East companies recognized net SECA revenues as follows:

		(in millions)
Three Months Ended June 30, 2006	$	-
Three Months Ended June 30, 2005		32
Six Months Ended June 30, 2006		35
Six Months Ended June 30, 2005		57
Total Net SECA Revenues Recognized Through June 2006		174

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 SECA billings. The FERC has not yet acted on the motion.

Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. SECA hearings were held in May 2006 to determine whether any of the SECA revenues should be refunded. Management negotiated settlements with certain major intervenors and is engaged in settlement talks with other intervenors. Based on those negotiations, the AEP East companies provided for $22 million in net refunds, of which $18 million was recorded in the second quarter of 2006 in Utility Operations Revenues in the Condensed Consolidated Statements of Operations. Unless all intervenor claims are fully settled, the ALJ is expected to issue an initial decision in the third quarter of 2006. At this time, management is unable to determine whether the outcome of the FERC's SECA rate proceeding and AEP's filed motion to force payment of unpaid invoices will have any additional adverse impact on future results of operations and cash flows.

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement allowing increases in our wholesale transmission OATT rates in three steps: first, beginning retroactively on November 1, 2005, second, beginning on April 1, 2006 when the SECA revenues were eliminated and third, beginning on August 1, 2006. We estimate that this rate increase will increase wholesale transmission revenues by $22 million in 2006 and $28 million in 2007.

The Elimination of T&O and SECA Rates and the FERC PJM Regional Transmission Rate Proceeding

In a separate proceeding, at our 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, among 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.

The following rate regimes have been proposed:

- 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 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.
- In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include 500 kV and higher existing facilities and some facilities at lower voltages in the Highway rate.
- Another proposal uses facilities 200 kV or higher in the Highway rate.
- 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.

All of these proposals are being challenged by a majority of transmission owners in the PJM region, who favor continuation of the PJM rate design. Hearings were held in April 2006.

The projected impact on the AEP East companies' revenues by plan follows:

- The AEP/AP Highway/Byway rate design would result in incremental net revenues of approximately $125 million per year for the transmission-owning AEP East companies.
- The competing Highway/Byway proposals filed by others would also produce incremental net revenues to the AEP East transmission-owning companies, but at a much lower level.
- The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal, when fully effective; however, the staff recommended a phase-in plan that would take an estimated six years to complete.

From the elimination of through and out (T&O) rates in December 2004 through the expiration of SECA rates on March 31, 2006, SECA transition rates failed to fully compensate the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone was not sufficient to replace the prior T&O service or temporary SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues and the less favorable terminated SECA revenues will require cost recovery through state retail rate proceedings pending any resolution that may result from the above FERC regional transmission rate proceeding. 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 starting March 30, 2006.
-

In Ohio, CSPCo's and OPCo are recovering the FERC approved OATT which 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.

We presently recover from retail customers approximately 65% of the reduction in transmission revenues of $128 million a year. On October 2, 2006, subject to refund in Virginia, that percentage will increase to 80%.

In July 2006, the ALJ who heard the regional rate case for the FERC rendered an initial decision recommending that the current transmission rates in PJM are unjust and unreasonable and should be revised effective April 1, 2006. The ALJ recommended a regional rate design similar to the staff's favorable "Postage Stamp" rate design discussed above. If approved, the new rates should result in recovery of a significant portion of the revenues lost due to elimination of T&O and SECA rates. However, the ALJ recommended a phase-in of the new "Postage Stamp" rates, which limits increases of any one pricing zone to 10% per year. We estimate the phase-in may occur over a six-year period. Once approved, the impacts of the new PJM rate design will flow directly to wholesale customers and to retail customers in Ohio and West Virginia. In our other jurisdictions, the additional transmission revenues can be expected to reduce retail rates in future rate proceedings.

Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate design. Parties to the proceeding have a right to file exceptions to both the ALJ initial decision and replies to the exceptions. We expect to file exceptions to certain aspects of the ALJ initial decision. The FERC will issue an order after considering the ALJ decision and subsequent filings.

Future results of operations, cash flows and financial condition would be adversely affected if the approved FERC transmission rates are not sufficient to replace the lost T&O/SECA revenues and the resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates.

Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved our proposed methodology to be used effective April 1, 2006 and beyond. The approved allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies. In February 2006, we filed with the FERC to remove TCC and TNC from the SIA and CSW Operating Agreement because those companies are in the final stages of exiting the generation business and have already ceased serving retail load. The FERC approved the removal of TCC and TNC from the SIA and CSW Operating Agreement effective May 1, 2006.

The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of cost recovery mechanisms and related sharing mechanisms by state. Our total trading and marketing margins are unaffected by the allocation methodology.

4. <u>CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING</u>

We are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant events occurring in 2006 related to customer choice and industry restructuring and update the 2005 Annual Report.

TEXAS RESTRUCTURING

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was $1.475 billion including carrying costs through September 2005. In December 2005, TCC adjusted its recorded net true-up regulatory asset to comply with the order. The PUCT issued an order on rehearing in April 2006, which made minor changes to, but otherwise affirmed, the February 2006 order. We appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties appealed the PUCT's true-up order claiming it permits TCC to over-recover stranded generation costs and other true-up items.

TCC Securitization Proceeding

TCC filed an application in March 2006 requesting to recover through securitization $1.8 billion of net stranded generation plant costs and related carrying costs through August 31, 2006. The $1.8 billion did not include TCC's other true-up items, which total $475 million and which would be refunded through a CTC over a period to be determined by the PUCT. See "CTC Proceeding for Other True-up Items" section of this note. Intervenors and the PUCT staff filed testimony regarding TCC's securitization request in April 2006. In May 2006, TCC filed a letter with the PUCT reducing its request by $6 million and reduced the recorded net recoverable asset by that amount. In May 2006, TCC and the other parties filed a settlement with the PUCT, which further reduced the securitizable amount by $77 million and settled several issues that would have delayed the sale of the securitization bonds. The PUCT approved the settlement in June 2006 authorizing $1.697 billion including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of $23 million, for a total of $1.72 billion. We anticipate issuing the securitization bonds by the end of the third quarter of 2006.

Consistent with certain prior securitization determinations, the PUCT issued a specific order in the securitization proceeding that calculated a $315 million cost-of-money benefit ($310 million through June 30, 2006 of which $70 million relates to the recorded benefit prior to June 30, 2006 and $240 million relates to the unrecorded benefit subsequent to June 30, 2006) for ADFIT resulting from the securitization request. The PUCT included the $315 million in the CTC refund of $475 million. In June, we transferred the effects of the ADFIT on recorded carrying cost from the securitizable asset to the CTC refund, thereby increasing the carrying costs identified to the securitizable assets in the table below.

TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the securitization less the proposed CTC refund would be more than sufficient to recover TCC's recorded net true-up regulatory asset. As a result, no additional impairment was recorded for the approved reduction in the amount to be securitized. However, the $77 million agreed upon reduction in the securitizable amount will have a negative impact on future earnings.

The differences between the securitization amount ordered by the PUCT of $1.7 billion and the recorded securitizable true-up regulatory asset of $1.5 billion at June 30, 2006 are detailed in the table below:

		(in millions)
Stranded Generation Plant Costs	$	974
Net Generation-related Regulatory Asset		249
Excess Earnings		(49)

Recorded Net Stranded Generation Plant Costs		1,174
Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs		375
Recorded Securitizable True-up Regulatory Asset		1,549
Unrecorded But Recoverable Equity Carrying Costs		217
Unrecorded Estimated July 2006 - August 2006 Debt Carrying Costs		17
Unrecorded Excess Earnings, Related Carrying Costs and Other		52
Settlement Reduction		(77)
Reduction for the ADITC and EDFIT Benefits		(61)
Approved Securitizable Amount		1,697
Unrecorded Securitization Bond Issuance Costs		23
Amount to be Securitized	$	1,720

Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up and securitization orders, the PUCT reduced net stranded generation plant costs 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 generating assets. TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions.

TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. The IRS issued its private letter ruling on May 9, 2006 and decided against the PUCT treatment and determined the PUCT's flowthrough to customers of the ADITC and EDFIT benefits would result in a normalization violation. TCC informed the PUCT on May 10, 2006 of the adverse ruling, however, the PUCT did not change its order on rehearing. TCC filed an appeal as noted earlier. As discussed in the "CTC Proceeding for Other True-up Items" section of this note, TCC proposed to defer the refunding of the ADITC and EDFIT in the securitization through its CTC filing until this normalization issue is resolved upon the IRS issuance of final normalization regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates $105 million as of June 30, 2006 and also a loss of claiming accelerated tax depreciation in future tax returns. Tax counsel has 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.

CTC Proceeding for Other True-up Items

In June 2006, TCC filed to implement a negative CTC (a rate reduction) for its net other true-up items over eight years. TCC will incur carrying costs on the net negative other true-up regulatory liability balances until fully refunded. The principal components of the CTC refund liability are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to TCC's stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance.

The differences between the components of TCC's Recorded Net Regulatory Liabilities for Other True-up Items as of June 30, 2006 and its CTC gross refund proposal are detailed below:

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		28
Retail Clawback including Carrying Costs		(63)
Deferred Over-recovered Fuel Balance		(181)

Retrospective ADFIT Benefit		(70)
Other		(4)
Recorded Net Regulatory Liabilities - Other True-up Items		(229)
Unrecorded Prospective ADFIT Benefit		(240)
Unrecorded Estimated July 2006 - August 2006 Carrying Costs		(6)
Gross CTC Refund Proposed		(475)
FERC Jurisdictional Fuel Refund Deferral		16
ADITC and EDFIT Benefit Refund Deferral		97
Net CTC Refund Proposed, After Deferrals		(362)
Rate Case Expense Surcharge		7
Net Refund Proposed, After Deferrals and Expenses	$	(355)

TCC requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of $16 million of FERC jurisdictional fuel over-recoveries (discussed below) and $97 million related to potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits discussed above. Although TCC proposed to refund the $355 million over eight years, certain intervenors have supported accelerated refunds. Management cannot predict the outcome of this filing. If the two contingent federal matters are resolved unfavorably, TCC will refund the $16 million and the $97 million plus carrying costs.

Fuel Balance Recoveries

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the same ruling should result. The favorable Federal District Court order, if upheld on appeal, could result in reductions to the over-recovered fuel principal balances of $8 million for TNC and $14 million ($16 million with carrying costs) for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the federal court system, it may file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies as an unfavorable FERC ruling may result in a reallocation of off-system sales margins from AEP East companies to AEP West companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

Carrying Costs on Net True-up Regulatory Assets Impacting Securitization and CTC Proceedings

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax weighted average cost of capital rate from its unbundled cost of service rate proceeding. The recorded embedded debt component of this carrying cost rate is 8.12%. Through June 30, 2006, TCC recorded $375 million of debt-related carrying costs on stranded generation plant costs impacting the securitization proceeding. TCC will continue to accrue debt-related carrying cost income until its net true-up regulatory asset is either securitized or fully recovered. Equity carrying costs of $217 million related to amounts securitized will be recognized in income as collected. The negative carrying cost, both debt and equity, on the net CTC refund is being fully recognized in income, and totals $52 million through June 2006.

In June 2006, the PUCT adopted a proposed rule that prospectively changes the carrying cost applied to TCC's CTC refund balance. TCC anticipates that the rule change will reduce the carrying cost that TCC will pay on its CTC balance from 11.79% to 7.47%. TCC anticipates that the change will reduce its annual refund by approximately $8 million. The rule provides for adjustments to the carrying cost rate during subsequent rate case proceedings.

Summary

Our recorded securitizable true-up regulatory asset at June 30, 2006 of $1.5 billion, net of the recorded net regulatory liabilities for other true-up items of $229 million, reflects the PUCT's orders in TCC's True-up Proceeding and its securitization proceeding. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in any subsequent proceedings or Court rulings, TCC expects to amortize its total securitizable true-up regulatory asset commensurate with recovery over 14 years. If we determine as a result of future PUCT orders or appeal court rulings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC is appealing the PUCT orders seeking relief in both state and federal court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. Municipal customers and other intervenors are also appealing the same PUCT orders seeking to further reduce TCC's true-up recoveries.

Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any future proceedings or court appeals. If TCC succeeds in its future appeals, it could have a material favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their expected appeals, or if the PUCT does not approve TCC's CTC filing as filed and as a result causes a normalization violation, it could have a material adverse effect on future results of operations, cash flows and financial condition.

Texas Restructuring - SPP

In June 2006, the PUCT adopted a rule delaying customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo and a small portion of TNC's business operate in SPP. Approximately 3% of TNC's operations are located in the SPP territory, with $13 million in net assets. 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) and TNC's customers, facilities and certificated service located in the SPP area to SWEPCo. If this petition is successful, SWEPCo will be our only remaining subsidiary affected by the delay in the SPP area.

OHIO RESTRUCTURING

Rate Stabilization Plans

In January 2005, the PUCO approved Rate Stabilization Plans (RSPs) for CSPCo and OPCo (the Ohio companies). The approved plans in each of 2006, 2007 and 2008 provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the request for additional revenues for specified costs. CSPCo's potential for the additional annual 4% generation rate increases is diminished by approximately three-quarters in 2006 and to a lesser extent in 2007 and 2008 due to the power acquisition rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding and the recovery of pre-construction costs for the IGCC plant (see "IGCC Plant" section of this note below). OPCo's potential for the additional annual 4% generation rate increases is diminished in 2006 by approximately one-quarter and to a lesser extent in 2007 due to the recovery of pre-construction costs for the IGCC plant. The RSPs also provide that the Ohio companies can recover in 2006, 2007 and 2008 estimated 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs net of financial transmission rights (FTR) revenue related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $8 million and $16 million for CSPCo and $17 million and $38 million for OPCo in the second quarter and first six months of 2006, respectively, from the RSP rate increases net of amortization of RSP regulatory assets. These increases also included the recognition of equity carrying costs. As of June 30, 2006, unrecognized equity carrying costs from 2004 and 2005, which are recognized over the three-year RSP period, totaled $36 million. As of June 30, 2006, the unamortized RSP regulatory assets to be recovered through December 31, 2008 were $47 million.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSPs and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. In Dayton Power & Light Company's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In an appeal concerning the First Energy companies' RSP, the Ohio Supreme Court held that the PUCO's decision to eliminate the offer to customers of a price determined through competitive bids was unlawful. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for the Ohio companies, which did not include a competitive bid process, and remanded the case to the PUCO for further proceedings, not inconsistent with the decision in the appeal of the First Energy companies' RSP. The PUCO has not yet acted on the remand of our RSP orders. In late July 2006, the PUCO acted on the First Energy companies' remand case ordering them to file a plan within 45 days to provide an option for customer participation in the electric market through competitive bids or other reasonable means and also held that the RSP shall remain effective.

In the Ohio companies' case, the Ohio Supreme Court did not address any other issues that had been raised on appeal, stating that its decision does not preclude the Ohio Consumers' Counsel from raising those issues in a future appeal. If the PUCO were to revise the Ohio companies' RSP to include a competitive bid process, the Ohio companies believe that the remainder of the original RSP order should remain in place. However, if on remand the PUCO were to modify other aspects of the RSP order, it could have a material effect on future results of operations and cash flows. Pending action by the PUCO on the remand, the Ohio companies' rates and the recovery of the RSP regulatory assets will continue. Management believes that the RSP regulatory assets remain probable of recovery.

IGCC Plant

In March 2005, the Ohio companies filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposed cost recovery associated with the IGCC plant in three phases: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, 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 projected $1.2 billion cost of the plant 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 the Ohio companies could request in 2006, 2007 and 2008 under their RSPs. As of June 30, 2006, the Ohio companies deferred $13 million of pre-construction IGCC costs.

In April 2006, the PUCO issued an order authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. No date for a further hearing has been set.

In June 2006, the PUCO approved a tariff to recover Phase 1 pre-construction costs over a twelve-month period effective July 1, 2006. In that order the PUCO indicated if the Ohio companies have not commenced continuous construction of the IGCC plant within five years of the order, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest.

In June 2006, the Industrial Energy Users - Ohio, an intervenor in the PUCO proceeding, filed a Complaint for Writ of Prohibition at the Ohio Supreme Court to prohibit the use of the PUCO's authorization by the Ohio companies to enforce the collection of the Phase 1 rates and to prohibit the PUCO from further entertaining any increase in rates for the IGCC project. The Ohio companies filed motions to dismiss the complaint with the Ohio Supreme Court. The Ohio companies believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful and that the PUCO has the authority to consider the remaining rate recovery phases associated with the IGCC project. The Ohio companies, however, cannot predict the ultimate outcome of this proceeding or of any appeal of the PUCO's April

2006 order. If the Ohio companies were prohibited from collecting the Phase 1 rates or if the PUCO's order is appealed and found to be unlawful, their future results of operations and cash flows would be adversely affected.

Transmission Rate Filing

In February 2006, in accordance with their RSPs, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective August 1, 2006 to recover their share of the cost of the new Wyoming-Jacksons Ferry transmission line. In May 2006, the PUCO issued an order approving the two-step increase in transmission rates with an over/under recovery mechanism effective April 1, 2006. In addition, the order provided for the deferral for future recovery of unrecovered transmission costs resulting from the loss of SECA revenues back to April 1, 2006. The new tariffs were filed with the PUCO and implemented in June 2006. We anticipate the order will result in increased revenues for CSPCo and OPCo of $27 million and $36 million, respectively, in 2006 and $44 million and $59 million, respectively, in 2007.

Storm Cost Recovery Filing

In March 2006, the Ohio companies filed an application with the PUCO to implement tariff riders to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. CSPCo and OPCo each requested recovery of approximately $12 million of such costs. A decision is expected in the third quarter of 2006.

PUCO Staff Report on Service Reliability

In December 2003, the Ohio companies entered into a stipulation agreement regarding distribution service reliability. The stipulation agreement covered the years 2004 and 2005 and, among other features, established certain distribution service reliability measures that the Ohio companies were to meet. In April 2006, the staff of the PUCO submitted a commission-ordered investigative report on the Ohio companies' compliance with the stipulation agreement. In the report, the staff asserted that the Ohio companies failed to fulfill all the terms of the stipulation agreement. The staff recommended various consequences for the PUCO's consideration, including the potential for civil forfeitures, monthly payments until the terms of the stipulation agreement have been met and/or providing credits to customers. The staff also suggested that the PUCO could explore possible improvements in the Ohio companies' management of the reliability process. Finally, the staff recommended that the Ohio companies file, in a companion docket, a comprehensive plan to improve their system reliability. The PUCO ordered the Ohio companies to respond to the staff's recommendations concerning consequences by May 23, 2006.

The Ohio companies responded on a timely basis explaining why they believed that they had substantially met the requirements of the stipulation agreement and offering to spend an additional $5 million on reliability without recovery. In July 2006, the PUCO directed the Ohio companies to earmark $10 million for future measures to improve service reliability. The Ohio companies will not be permitted to recover any of that amount from customers. The PUCO further indicated that it will determine where and how the $10 million will best be applied. In a separate docket, the PUCO directed the Ohio companies to submit a plan to enhance service reliability no later than October 6, 2006. The PUCO indicated that it will set a procedural schedule in the future to consider the Ohio companies' plan.

Customer Choice Deferrals

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies defer customer choice implementation costs and related carrying costs in excess of $20 million each. The agreements provide for the deferral of these costs as regulatory assets until the next distribution base rate cases. Through June 30, 2006, we incurred $95 million of such costs and, accordingly, we deferred $47 million of such costs for probable future recovery in distribution rates. We have not recorded $8 million of equity carrying costs, which are not recognized until collected.

Pursuant to the RSPs, recovery of these amounts is subject to PUCO review and deferred until the next distribution rate filing to change rates after December 31, 2008. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2005 Annual Report, we continue to be involved in various legal matters. The 2005 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2005 Annual Report. See disclosure below for significant matters and changes in status subsequent to the disclosure made in our 2005 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states alleged 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 court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 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. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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. 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, 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 one 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 Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that would exclude most of the challenged activities from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability 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 future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In July 2004, two special interest groups, Sierra Club and Public Citizen, issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at the Welsh Plant. SWEPCo filed a response to the complaint in May 2005. Other preliminary motions have been filed and are pending before the Court.

In July 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.

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, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims

In July 2004, attorneys general from eight states and the corporation counsel for 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. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts associated with global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court's dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have been completed. We believe the actions are without merit and intend to defend vigorously against the claims.

Ontario Litigation

In June 2005, we and nineteen nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The time limit for serving the defendants expired, but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, emitted NO_X, SO_2 and particulate matter that harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend vigorously against it.

OPERATIONAL

Power Generation Facility and TEM Litigation

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility. The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's funded obligations as a liability. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper lease, our maximum cash payment could be as much as $525 million. Because we report Juniper's funded obligations totaling $525 million related to the Facility on our Condensed Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to TEM for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

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 April 2004, OPCo gave notice to TEM that OPCo (a) was suspending performance of its obligations under the PPA; (b) would seek a declaration from the District Court that the PPA was terminated; and (c) would pursue TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM breached the contract and awarded us damages of $123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. We asked the court to modify the judgment to (a) award a termination payment to us under the terms of the PPA; (b) grant our attorneys' fees; and (c) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted our motion for reconsideration concerning TEM's parent guaranty and increased our judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration. In March 2006, the trial judge amended the January 2006 order eliminating the additional $50 million damage award.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found unenforceable by the court ultimately deciding the case, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover the claimed termination value damages from TEM. Management continues to review all options associated with the Facility investment in order to minimize any long-term negative results.

Enron Bankruptcy

In connection with our 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 July 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 reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. The state court of appeals heard oral argument on the appeal in June 2006. 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 filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

In October 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 reservoir 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 reservoir 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.

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 June 2006, we started mediation with BOA and Enron concerning these gas disputes.

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 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 (see Note 8).

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 the fourth quarter of 2002 and the first quarter of 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 July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice.

Natural Gas Markets Lawsuits

In November 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 have been 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 had been transferred to the United States District Court for the District of Nevada but subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine and in December 2005, the judge dismissed two additional cases on the same ground. Plaintiffs in these cases appealed the decisions. We will continue to defend vigorously each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies, including AEP and AEPES, making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases were consolidated. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied. In October 2005, the Court granted the plaintiffs motion for class certification. The defendants filed a petition for leave to appeal this decision. We intend to continue to defend vigorously against these claims.

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 because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the Nevada utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The Nevada utilities' request for a rehearing was denied. The Nevada utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

6. 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 June 30, 2006, the maximum future payments for all the LOCs are approximately $31 million with maturities ranging from July 2006 to March 2007.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $58 million with maturity dates ranging from July 2006 to February 2012.

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. This guarantee ends upon depletion of reserves and final reclamation is completed. At June 30, 2006, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036. The cost for final reclamation during the period 2029 through 2036 is estimated at approximately $39 million.

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. Prior to June 30, 2006, we entered into several sale agreements. The status of certain sales agreements is discussed in the "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 Note 5). 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 June 30, 2006, the maximum potential loss for these lease agreements was approximately $54 million ($35 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.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least the lessee obligation amount specified in the lease, which declines over the lease term from approximately 86% to 77% of the projected fair market value of the equipment. At June 30, 2006, 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 rail car lease arrangements that do not utilize this type of structure.

7. <u>COMPANY-WIDE STAFFING AND BUDGET REVIEW</u>

As a result of a company-wide staffing and budget review in the second quarter of 2005, we identified approximately 500 positions for elimination. Pretax severance benefits expense of $24 million was recorded (primarily in Maintenance and Other Operation within the Utility Operations segment) in the second quarter of 2005.

The following table shows the accrual as of December 31, 2005 (reflected primarily in Current Liabilities - Other) and the activity during the first six months of 2006, which eliminated the accrual as of June 30, 2006:

	Amount (in millions)	
Accrual at December 31, 2005	$	12
Less: Total Payments		8
Less: Accrual Adjustments		4
Accrual at June 30, 2006	$	-

The accrual adjustments were recorded primarily in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

8. DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

DISPOSITIONS

2006

Compresion Bajio S de R.L. de C.V. (Investments - Other segment)

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 received an indicative offer for Bajio in September 2005. The sale was completed in February 2006 for approximately $29 million with no effect on our 2006 results of operations.

2005

Houston Pipe Line Company LP (HPL) (Investments - Gas Operations segment)

During 2005, we sold our interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. Although the assets were legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $379 million as of June 30, 2006 and December 31, 2005, which is reflected in Deferred Credits and Other on our accompanying Condensed Consolidated Balance Sheets. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a potential resulting inability to use the cushion gas (see “Enron Bankruptcy” section of Note 5). The HPL operations did not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008 and the cushion gas arrangement. In addition, we continue to hold forward gas contracts not sold with the gas pipeline and storage assets.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement and was amended through a series of agreements that AEP and Centrica entered in March 2005. Also in March 2005, we received payments related to the ESM of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005. In March 2006, we received a payment of $70 million related to the ESM for 2005. The ESM payment for 2006 is contingent on Centrica’s future operating results and is capped at $20 million. The payments are reflected in Gain/Loss on Disposition of Assets, Net on our accompanying Condensed Consolidated Statements of Operations.

DISCONTINUED OPERATIONS

Certain of our operations were determined to be discontinued operations and have been classified as such for all periods presented. Results of operations of these businesses have been classified as shown in the following table (in millions):

Three Months ended June 30, 2006 and 2005:

	SEEBOARD (a)	U.K. Generation (b)	Total
2006 Revenue	$ -	$ -	$ -
2006 Pretax Income	-	4	4
2006 Earnings, Net of Tax	-	3	3
2005 Revenue	$ -	$ -	$ -
2005 Pretax Income	-	-	-
2005 Earnings, Net of Tax	3	-	3

Six Months ended June 30, 2006 and 2005:

	SEEBOARD (a)	U.K. Generation(c)	Total
2006 Revenue	$ -	$ -	$ -
2006 Pretax Income	-	9	9
2006 Earnings, Net of Tax	-	6	6
2005 Revenue (Expense)	$ -	$ (8)	$ (8)
2005 Pretax Loss	-	(8)	(8)
2005 Earnings (Loss), Net of Tax	9	(5)	4

(a) The amounts relate to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) The amounts relate to tax adjustments from the sale.
(c) The 2006 amounts relate to a release of accrued liabilities for the London office lease and tax adjustments from the sale. Amounts in 2005 relate to purchase price true-up adjustments and tax adjustments from the sale.

There were no cash flows used for or provided by operating, investing or financing activities related to our discontinued operations for the six months ended June 30, 2006 and 2005.

ASSETS HELD FOR SALE

Texas Plants - Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to Golden Spread Electric Cooperative, Inc. (Golden Spread), subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsfield (the nonaffiliated co-owners). By May 2004, we received notice from the nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of the nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were challenged in State District Court in Dallas County by Golden Spread. Golden Spread alleges that the Public Utilities Board of the City of Brownsfield exceeded its legal authority and that the Oklahoma Municipal Power Authority did not exercise its right of first refusal in a timely manner. Golden Spread requested that the court declare the nonaffiliated co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of Golden Spread on October 10, 2005. TCC and the nonaffiliated co-owners filed an appeal to the Court of Appeals for the Fifth District at Dallas. On May 18, 2006, the Court of Appeals for the Fifth District at Dallas reversed the trial court's judgment in favor of Golden Spread and held that the City of Brownsville properly exercised its right of first refusal to acquire TCC's share of Oklaunion. Golden Spread requested a rehearing in the matter, and its petition was denied. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets related to the Oklaunion Power Station are classified as Assets Held for Sale on our Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005. 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.

Assets Held for Sale at June 30, 2006 and December 31, 2005 are as follows:

Texas Plants	June 30, 2006	December 31, 2005
Assets:	**(in millions)**	
Other Current Assets	$ 2	$ 1
Property, Plant and Equipment, Net	44	43
Total Assets Held for Sale	$ 46	$ 44

9. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the following plans for the three and six months ended June 30, 2006 and 2005:

	Pension Plans		Other Postretirement Benefit Plans	
Three Months Ended June 30, 2006 and 2005:	**2006**	**2005**	**2006**	**2005**
		(in millions)		
Service Cost	$ 24	$ 23	$ 10	$ 10
Interest Cost	57	56	25	26
Expected Return on Plan Assets	(83)	(78)	(23)	(22)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	19	14	5	7
Net Periodic Benefit Cost	$ 17	$ 15	$ 24	$ 28

	Pension Plans		Other Postretirement Benefit Plans	
Six Months Ended June 30, 2006 and 2005:	**2006**	**2005**	**2006**	**2005**
		(in millions)		
Service Cost	$ 48	$ 46	$ 20	$ 21
Interest Cost	114	112	50	53
Expected Return on Plan Assets	(166)	(155)	(46)	(45)
Amortization of Transition Obligation	-	-	14	14
Amortization of Net Actuarial Loss	39	27	10	14
Net Periodic Benefit Cost	$ 35	$ 30	$ 48	$ 57

10. STOCK-BASED COMPENSATION

The Amended and Restated American Electric Power System Long-Term Incentive Plan (the Plan) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. A maximum of 9,000,000 shares may be used under this plan for full value shares awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders both adopted the original Plan in 2000 and the amended and restated version in 2005. Except for 10,000 stock options granted in the third quarter of 2005, the Board of Directors has not granted stock options since 2004. The following sections provide further information regarding each type of stock-based compensation award the Board of Directors has granted.

We adopted SFAS 123R, effective January 1, 2006. See the SFAS 123 (revised 2004) "Share-Based Payment" section of Note 2 for additional information.

Stock Options

For all stock options previously granted, the exercise price equaled or exceeded the market price of AEP's common stock on the date of grant. Historically the Board of Directors has granted stock options with a ten-year term that generally vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. Compensation cost for stock options is recorded over the vesting period based on the fair value on the grant date. The Plan does not specify a maximum contractual term for stock options.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled, expired or forfeited. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

The Board of Directors did not award any stock options during the three and six months ended June 30, 2006 and 2005.

The total fair value of stock options vested and the total intrinsic value of options exercised during the three and six months ended June 30, 2006 and 2005 are as follows:

	Three Months Ended		Six Months Ended	
	2006	**2005**	**2006**	**2005**
Stock Options		**(in thousands)**		
Fair Value of Stock Options Vested	$ -	$ 6	$ 3,665	$ 5,036
Intrinsic Value of Options Exercised (a)	148	3,337	1,537	7,657

(a) Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the three and six months ended June 30, 2006 is as follows:

	Three Months Ended		Six Months Ended	
	Options (in thousands)	**Weighted Average Exercise Price**	**Options (in thousands)**	**Weighted Average Exercise Price**
Outstanding at beginning of period	5,962	$ 34.11	6,222	$ 34.16
Granted	-	N/A	-	N/A

Exercised/converted	(22)		27.27	(195)		28.51
Expired	-		N/A	-		N/A
Forfeited	(88)		37.77	(175)		43.10
Outstanding at June 30, 2006	5,852		34.08	5,852		34.08
Options exercisable at June 30, 2006	5,587	$	34.33	5,587	$	34.33

The following table summarizes information about AEP stock options outstanding at June 30, 2006.

Options Outstanding

2006 Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Remaining Life (in years)		Weighted Average Exercise Price		Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	1,443	6.1	$	27.37	$	9,924
$30.76 - $38.65	4,039	3.5		35.44		520
$43.79 - $49.00	370	4.9		45.43		-
	5,852	4.2		34.08	$	10,444

The following table summarizes information about AEP stock options exercisable at June 30, 2006.

Options Exercisable

2006 Range of Exercise Prices	Number Exercisable (in thousands)	Weighted Average Remaining Life (in years)		Weighted Average Exercise Price		Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	1,238	5.9	$	27.29	$	8,621
$30.76 - $35.63	3,979	3.4		35.50		347
$43.79 - $49.00	370	4.9		45.43		-
	5,587	4.1		34.33	$	8,968

The proceeds received from exercised stock options are included in common stock and paid-in capital. For options issued through December 31, 2005, the grant date fair value of each option award was estimated using a Black-Scholes option-pricing model with weighted average assumptions. Expected volatilities are estimated using the historical monthly volatility of our common stock for the 36-month period prior to each grant. A seven-year average expected term is also assumed. The risk-free rate is the yield for U.S. Treasury securities with a remaining life equal to the expected seven-year term of AEP stock options on the grant date.

Performance Units

Our performance units are equal in value to an equivalent number of shares of AEP common stock. The number of performance units held is multiplied by a performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors (HR Committee) and can range from 0 percent to 200 percent. Performance units are typically paid in cash at the end of a three-year performance and vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units ("AEP Career Shares") until after the end of the participant's AEP career. AEP Career Shares have a value equivalent to the market value of an equal number of AEP common shares and are generally paid in cash after the participant's termination of employment.

Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. The compensation cost for performance units is recorded over the vesting period and the liability for both the performance units and AEP Career Shares is adjusted for changes in value. The vesting period of all performance units is three years.

Our Board of Directors awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the three and six months ended June 30, 2006 and 2005 as follows:

	Three Months Ended		Six Months Ended	
	2006	2005	2006	2005
Performance Units				
Awarded Units (in thousands)	-	-	864	1,013
Unit Fair Value at Grant Date	$ N/A	$ N/A	$ 37.36	$ 34.02
Vesting Period (years)	N/A	N/A	3	3
Performance Units and AEP Career Shares (Reinvested Dividends Portion)				
Awarded Units (in thousands)	31	22	61	46
Weighted Average Grant Date Fair Value	$ 34.90	$ 35.73	$ 35.10	$ 34.94
Vesting Period (years) (a)	3	3	3	3

(a) Vesting Period (years) range from 0 - 3 years. The Vesting Period of the reinvested dividends is equal to the remaining life of the related performance units and AEP Career Shares.

In January 2006, the HR Committee certified a performance score of 49% for performance units originally granted for the 2003 through 2005 performance period. As a result, 108,486 performance units were earned. Of this amount 33,296 were mandatorily deferred as AEP Career Shares, 4,360 were voluntarily deferred into the Incentive Compensation Deferral Program and the remainder were paid in cash. The score for the 2002 through 2004 performance period was discretionarily reduced to 0% by the HR Committee so no performance units were earned, paid or deferred during the three and six months ended June 30, 2005.

The cash payouts for the three and six months ended June 30, 2006 and 2005 were as follows:

	Three Months Ended		Six Months Ended	
	2006	2005	2006	2005
	(in thousands)			
Cash payouts for Performance Units	$ -	$ -	$ 2,630	$ -
Cash payouts for AEP Career Share distributions	479	463	955	1,028

The performance unit scores for all open performance periods are dependent on two equally-weighted performance measures: three-year total shareholder return measured relative to the S&P Utilities Index and three-year cumulative earnings per share measured relative to a board-approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 days of the performance period.

The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

Restricted Shares and Restricted Stock Units

Our Board of Directors granted 300,000 restricted shares to the Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005 and 50,000 vested on January 1, 2006. The remaining 200,000 restricted shares vest, subject to his continued employment, in approximately equal thirds on November 30, 2009, 2010 and 2011. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. The maximum term for these restricted shares is eight years. The Board of Directors has not granted other restricted shares. Dividends on our restricted shares are paid in cash.

Our Board of Directors may also grant restricted stock units, which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. Amounts equivalent to dividends paid on AEP shares accrue as additional restricted stock units that vest on the last vesting date associated with the underlying units. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market price. The maximum contractual term of these restricted stock units is six years.

In January 2006, our Board of Directors also granted restricted stock units with performance vesting conditions to certain employees who are integral to our project to design and build an IGCC power plant. Twenty percent of these awards vest on each of the first three anniversaries of the grant date. An additional 20% vest on the date the IGCC plant achieves commercial operations. The remaining 20% vest one year after the IGCC plant achieves commercial operations, subject to achievement of plant availability targets.

Our Board of Directors awarded restricted stock units, including units awarded for dividends, for the three and six months ended June 30, 2006 and 2005 as follows:

	Three Months Ended 2006	Three Months Ended 2005	Six Months Ended 2006	Six Months Ended 2005
Restricted Stock Units				
Awarded Units (in thousands)	8	99	45	126
Weighted Average Grant Date Fair Value	$ 34.49	$ 35.55	$ 35.57	$ 35.03

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the three and six months ended June 30, 2006 and 2005 were as follows:

	Three Months Ended 2006	Three Months Ended 2005	Six Months Ended 2006	Six Months Ended 2005
Restricted Shares and Restricted Stock Units		(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 609	$ 26	$ 2,889	$ 2,159
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested	571	30	3,515	2,608

A summary of the status of our nonvested restricted shares and restricted stock units as of June 30, 2006, and changes during the three and six months ended June 30, 2006 are as follows:

	Three Months Ended		Six Months Ended	
Nonvested Restricted Shares and Restricted Stock Units	**Shares/Units**	**Weighted Average Grant Date Fair Value**	**Shares/Units**	**Weighted Average Grant Date Fair Value**

	(in thousands)			(in thousands)		
Nonvested at beginning of period	454	$	33.06	497	$	32.19
Granted	8		34.49	45		35.57
Vested	(17)		35.36	(96)		30.04
Forfeited	(15)		35.59	(16)		35.49
Nonvested at June 30, 2006	430		32.91	430		32.91

The total aggregate intrinsic value of nonvested restricted shares and restricted stock units as of June 30, 2006 was $14.7 million and the weighted average remaining contractual life was 3.05 years.

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the three and six months ended June 30, 2006 and 2005 were as follows:

	Three Months Ended				Six Months Ended			
	2006		2005		2006		2005	
Share-based Compensation Plans			(in thousands)					
Compensation cost for share-based payment arrangements	$	1,209	$	5,352	$	3,639	$	8,268
Actual tax benefit realized		424		1,873		1,274		2,894
Total compensation cost capitalized		42		995		620		1,396

During the three and six months ended June 30, 2006 and 2005, there were no significant modifications affecting any of our share-based payment arrangements.

As of June 30, 2006, there was $43 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the Plan. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the liability is revalued each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.63 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the three and six months ended June 30, 2006 and 2005 were as follows:

	Three Months Ended				Six Months Ended			
	2006		2005		2006		2005	
Share-based Compensation Plans			(in thousands)					
Cash received from stock options exercised	$	609	$	13,260	$	5,561	$	28,413
Actual tax benefit realized for the tax deductions from stock options exercised		52		1,160		538		2,675

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and restricted stock unit vesting. Although we do not currently anticipate any changes to this practice, we could use reacquired shares, shares acquired in the open market specifically for distribution under the Plan or any combination thereof for this purpose. The number of new shares issued to fulfill vesting restricted stock units is generally reduced, at the participant's election, to offset AEP's tax withholding obligation.

11. INCOME TAXES

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109 "Accounting for Income Taxes." Based on the new law, we reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006 we recorded a net reduction to Deferred Income Taxes on the Condensed Consolidated Balance Sheet of $48 million of which $2 million was credited to Income Tax Expense and $46 million credited to Regulatory Assets based upon the related rate-making treatment.

12. BUSINESS SEGMENTS

As outlined in our 2005 Annual Report, our business strategy and the core of our business are to focus on domestic electric utility operations. Our previous decision to no longer pursue business interests outside of our domestic core utility assets led us to divest such noncore assets. Consequently, the significance of our three Investments segments has declined.

Our 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.

Investments - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.
- We disposed of our gas pipeline and storage assets in 2005 with the sale of HPL (see "Dispositions" section of Note 8).

Investments - UK Operations

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.
- We classified UK Operations as Discontinued Operations during 2003 and sold them in 2004.

Investments - Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.

The tables below present segment income statement information for the three and six months ended June 30, 2006 and 2005 and balance sheet information as of June 30, 2006 and December 31, 2005. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

	Investments		
		Other	Consolidated

	Utility Operations	Gas Operations	UK Operations		All Other (a)	Reconciling Adjustments	
				(in millions)			
Three Months Ended June 30, 2006							
Revenues from:							
External Customers	$ 2,810	$ (15)	$ -	$ 141	$ -	$ -	$ 2,936
Other Operating Segments	(11)	17	-	2	-	(8)	-
Total Revenues	$ 2,799	$ 2	$ -	$ 143	$ -	$ (8)	$ 2,936
Income (Loss) Before Discontinued Operations	$ 160	$ 2	$ -	$ 13	$ (3)	$ -	$ 172
Discontinued Operations, Net of Tax	-	-	3	-	-	-	3
Net Income (Loss)	$ 160	$ 2	$ 3	$ 13	$ (3)	$ -	$ 175

	Investments						
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended June 30, 2005							
Revenues from:							
External Customers	$ 2,680	$ 19	$ -	$ 120	$ -	$ -	$ 2,819
Other Operating Segments	22	(17)	-	3	-	(8)	-
Total Revenues	$ 2,702	$ 2	$ -	$ 123	$ -	$ (8)	$ 2,819
Income (Loss) Before Discontinued Operations	$ 247	$ (2)	$ -	$ (1)	$ (26)	$ -	$ 218
Discontinued Operations, Net of Tax	-	-	-	3	-	-	3
Net Income (Loss)	$ 247	$ (2)	$ -	$ 2	$ (26)	$ -	$ 221

	Investments						
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Six Months Ended June 30, 2006							
Revenues from:							
External Customers	$ 5,797	$ (33)	$ -	$ 280	$ -	$ -	$ 6,044
Other Operating Segments	(29)	38	-	5	1	(15)	-
Total Revenues	$ 5,768	$ 5	$ -	$ 285	$ 1	$ (15)	$ 6,044
Income (Loss) Before Discontinued Operations	$ 525	$ 1	$ -	$ 29	$ (5)	$ -	$ 550
	-	-	6	-	-	-	6

Discontinued Operations, Net of Tax							
Net Income (Loss)	$ 525	$ 1	$ 6	$ 29	$ (5)	$ -	$ 556

	Utility Operations	Gas Operations	UK Operations	Investments Other (in millions)	All Other (a)	Reconciling Adjustments	Consolidated
Three Months Ended June 30, 2005							
Revenues from:							
External Customers	$ 5,285	$ 376	$ -	$ 223	$ -	$ -	$ 5,884
Other Operating Segments	101	(90)	-	9	1	(21)	-
Total Revenues	$ 5,386	$ 286	$ -	$ 232	$ 1	$ (21)	$ 5,884
Income (Loss) Before Discontinued Operations	$ 600	$ 8	$ -	$ 4	$ (40)	$ -	$ 572
Discontinued Operations, Net of Tax	-	-	(5)	9	-	-	4
Net Income (Loss)	$ 600	$ 8	$ (5)	$ 13	$ (40)	$ -	$ 576

	Utility Operations	Gas Operations	UK Operations	Investments Other (in millions)	All Other(b)	Reconciling Adjustments (b)	Consolidated
As of June 30, 2006							
Total Property, Plant and Equipment	$ 39,653	$ 1	$ -	$ 834	$ 3	$ -	$ 40,491
Accumulated Depreciation and Amortization	14,965	-	-	126	2	-	15,093
Total Property, Plant and Equipment - Net	$ 24,688	$ 1	$ -	$ 708	$ 1	$ -	$ 25,398
Total Assets	$ 34,689	$ 735(c)	$ 630(d)	$ 577	$ 10,400	$ (10,847)	$ 36,184
Assets Held for Sale	46	-	-	-	-	-	46

	Utility Operations	Gas Operations	UK Operations	Investments Other (in millions)	All Other(b)	Reconciling Adjustments (b)	Consolidated
As of December 31, 2005							
Total Property, Plant and Equipment	$ 38,283	$ 2	$ -	$ 833	$ 3	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	1	-	112	1	-	14,837

Total Property, Plant and Equipment - Net	$ 23,560	$ 1	$ -	$ 721	$ 2	$ -	$ 24,284
Total Assets	$ 34,339	$ 1,199(e)	$ 632(f)	$ 509	$ 9,463	$ (9,970)	$ 36,172
Assets Held for Sale	44	-	-	-	-	-	44

(a) All Other includes the parent company's interest income and expense, as well as other nonallocated costs.
(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 (included in All Other) in subsidiary companies.
(c) Total Assets of $735 million for the Investments-Gas Operations segment include $344 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $391 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.
(d) Total Assets of $630 million for the Investments-UK Operations segment include $614 million in affiliated accounts receivable related mainly to federal income taxes that are eliminated in consolidation. The majority of the remaining $16 million in assets represents value-added tax receivables.
(e) Total Assets of $1.2 billion for the Investments-Gas Operations segment include $429 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $770 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.
(f) Total Assets of $632 million for the Investments-UK Operations segment include $613 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining $19 million in assets represents cash equivalents and value-added tax receivables.

13. FINANCING ACTIVITIES

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:

Type of Debt	June 30, 2006	December 31, 2005
	(in millions)	
Commercial Paper - AEP (a)	$ 144	$ -
Commercial Paper - JMG (b)	5	10
Line of Credit - Sabine (c)	10	-
	$ 159	$ 10

(a) The interest rate at June 30, 2006 was 5.37%.

(b) The interest rate at June 30, 2006 and December 31, 2005 was 5.47% and 4.47%, respectively.

(c) The interest rate at June 30, 2006 was 6.38%.

<u>Long-term Debt</u>

Our outstanding long-term debt is as follows:

Type of Debt	June 30, 2006	December 31, 2005
	(in millions)	
Pollution Control Bonds	$ 2,051	$ 1,935
Senior Unsecured Notes	8,677	8,226
First Mortgage Bonds	96	196
Defeased First Mortgage Bonds (a)	26	26
Notes Payable	886	904
Securitization Bonds	617	648
Notes Payable To Trust	113	113
Other Long-Term Debt (b)	244	236
Unamortized Discount (net)	(65)	(58)
Total Long-term Debt Outstanding	12,645	12,226
Less Portion Due Within One Year	800	1,153
Long-term Portion	$ 11,845	$ 11,073

(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 $18 million at both June 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of $2 million are included in Other Temporary Cash Investments at both June 30, 2006 and December 31, 2005 and $21 million is included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at both June 30, 2006 and December 31, 2005. 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 June 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of $9 million and $1 million at June 30, 2006 and December 31, 2005, respectively, are included in Other Temporary Cash Investments and $0 and $8 million are included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005, respectively. 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 of $267 million and $264 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005, respectively.

Long-term debt issued, retired and principal payments made during the first six months of 2006 are shown in the tables below.

Company	Type of Debt	Principal Amount (in millions)		Interest Rate (%)	Due Date
Issuances:					
APCo	Pollution Control Bonds	$	50	Variable	2036
APCo	Senior Unsecured Note		250	5.55	2011
APCo	Senior Unsecured Note		250	6.375	2036
I&M	Pollution Control Bonds		50	Variable	2025
OPCo	Pollution Control Bonds		65	Variable	2036
OPCo	Senior Unsecured Note		350	6.00	2016
SWEPCo	Pollution Control Bonds		82	Variable	2018
Total Issuances		$	1,097(a)		

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

(a) Amount indicated on statement of cash flows of $1,081 million is net of issuance costs and unamortized premium or discount.

In July 2006, AEGCo remarketed its outstanding $45 million pollution control bonds, resulting in a new interest rate of 4.15%. No proceeds were received related to this remarketing. The principal amount of the pollution control bonds is reflected in Long-term Debt on our Condensed Consolidated Balance Sheet as of June 30, 2006.

Company	Type of Debt	Principal Amount Paid (in millions)		Interest Rate (%)	Due Date
Retirements and Principal Payments:					
AEP	Senior Unsecured Note	$	396	6.125	2006
APCo	First Mortgage Bonds		100	6.80	2006
I&M	Pollution Control Bonds		50	6.55	2025
OPCo	Notes Payable		3	6.81	2008
OPCo	Notes Payable		3	6.27	2009
SWEPCo	Notes Payable		3	4.47	2011
SWEPCo	Notes Payable		1	Variable	2008

SWEPCo	Pollution Control Bonds		82	6.10	2018
TCC	Securitization Bonds		31	5.01	2010
Non-Registrant:					
AEP Subsidiaries	Notes Payable		3	Variable	2017
CSW Energy	Notes Payable		4	5.88	2011
Total Retirements and Principal Payments		$	676		

Credit Facilities

In April 2006, we amended the terms and increased the size of our credit facilities from $2.7 billion to $3 billion. The amended facilities are structured as two $1.5 billion credit facilities, with an option in each to issue up to $200 million as letters of credit, expiring separately in March 2010 and April 2011. We also terminated an existing $200 million letter of credit facility.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As co-owner of the Rockport Plant, we engage in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and co-owner of the Rockport Plant.

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. 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. Costs of operating the plant are divided between the co-owners.

Results of Operations

Net Income increased $0.1 million for the second quarter of 2006 compared with the second quarter of 2005. Net Income increased $0.5 million for the six months ended 2006 compared with the six months ended 2005. 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 which is calculated and adjusted monthly.

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)

Second Quarter of 2005		$ 2.1
Change in Gross Margin:		
Wholesale Sales		0.3
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	0.3	
Interest Expense	(0.1)	
Total Change in Operating Expenses and Other		0.2
Income Tax Expense		(0.4)
Second Quarter of 2006		$ 2.2

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased $0.3 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

The decrease in Other Operation and Maintenance expenses resulted from decreased maintenance cost at Rockport Plant during 2006 due to the timing of outages in 2006 and 2005.

Income Taxes

The increase in Income Tax Expense is primarily due to an increase in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income
(in millions)

Six Months Ended June 30, 2005		$ 4.6
Change in Gross Margin:		
Wholesale Sales		3.0
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(1.4)	
Interest Expense	(0.2)	
Total Change in Operating Expenses and Other		(1.6)
Income Tax Expense		(0.9)
Six Months Ended June 30, 2006		$ 5.1

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased $3 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

The increase in Other Operation and Maintenance expenses resulted from increased maintenance cost at Rockport Plant during a planned outage in 2006 and credits allocated to us in February 2005 from the cancellation and settlement of corporate owned life insurance policies.

Income Taxes

The increase in Income Tax Expense is primarily due to an increase in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Off-Balance Sheet Arrangements

In prior years, we entered into an off-balance sheet arrangement for the lease of Rockport Plant Unit 2. Our current guidelines restrict the use of off-balance sheet financing entities or structures to allow only traditional operating lease arrangements. Our off-balance sheet arrangement has not changed significantly since year-end. For complete information on our off-balance sheet arrangement see “Off-balance Sheet Arrangements” in the “Management’s Narrative Financial Discussion and Analysis” section of our 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

In July 2006, we remarketed $45 million of pollution control bonds at a rate of 4.15% compared to a previous rate of 4.05% until July 14, 2011, the next remarketing date.

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 2005 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.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(Unaudited)
(in thousands)

	Three Months Ended 2006	Three Months Ended 2005	Six Months Ended 2006	Six Months Ended 2005
OPERATING REVENUES	$ 77,195	$ 65,082	$ 155,346	$ 131,628
EXPENSES				
Fuel for Electric Generation	45,087	33,233	89,048	68,368
Rent - Rockport Plant Unit 2	17,071	17,071	34,142	34,142
Other Operation	3,122	3,126	6,217	5,573
Maintenance	1,930	2,272	4,716	3,990
Depreciation and Amortization	5,959	5,989	11,907	11,945
Taxes Other Than Income Taxes	1,028	1,051	2,098	2,075
TOTAL	74,197	62,742	148,128	126,093
OPERATING INCOME	2,998	2,340	7,218	5,535
Other Income (Expense):				
Interest Income	-	24	-	24
Allowance for Equity Funds Used During Construction	24	60	24	60
Interest Expense	(641)	(562)	(1,363)	(1,196)
INCOME BEFORE INCOME TAXES	2,381	1,862	5,879	4,423
Income Tax Expense (Credit)	161	(211)	731	(166)
NET INCOME	$ 2,220	$ 2,073	$ 5,148	$ 4,589

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three and Six Months Ended June 30, 2006 and 2005
(Unaudited)
(in thousands)

	Three Months Ended 2006	Three Months Ended 2005	Six Months Ended 2006	Six Months Ended 2005
BALANCE AT BEGINNING OF PERIOD	$ 26,968	$ 25,813	$ 26,038	$ 24,237
Net Income	2,220	2,073	5,148	4,589
Cash Dividends Declared	2,012	939	4,010	1,879
BALANCE AT END OF PERIOD	$ 27,176	$ 26,947	$ 27,176	$ 26,947

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
June 30, 2006 and December 31, 2005
(Unaudited)
(in thousands)

	2006	2005
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	$ 26,930	$ 29,671
Fuel	18,513	14,897
Materials and Supplies	7,614	7,017
Accrued Tax Benefits	1,311	2,074
Prepayments and Other	88	9
TOTAL	54,456	53,668
PROPERTY, PLANT AND EQUIPMENT		
Electric - Production	689,407	684,721
Other	2,342	2,369
Construction Work in Progress	9,759	12,252
Total	701,508	699,342
Accumulated Depreciation and Amortization	393,630	382,925
TOTAL - NET	307,878	316,417
Noncurrent Assets	8,409	6,618
TOTAL ASSETS	$ 370,743	$ 376,703

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 36,989	$ 35,131
Accounts Payable:		
General	494	926
Affiliated Companies	17,351	22,161
Long-term Debt Due Within One Year	-	44,828
Accrued Taxes	5,486	3,055
Accrued Rent - Rockport Plant Unit 2	4,963	4,963
Other	1,319	1,228
TOTAL	66,602	112,292
NONCURRENT LIABILITIES		
Long-term Debt	44,833	-
Deferred Income Taxes	21,765	23,617
Asset Retirement Obligations	1,400	1,370
Regulatory Liabilities and Deferred Investment Tax Credits	81,154	82,689
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	91,548	94,333
Obligations Under Capital Leases	11,831	11,930
TOTAL	252,531	213,939
TOTAL LIABILITIES	319,133	326,231
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $1,000 Par Value Per Share Authorized and Outstanding - 1,000 Shares	1,000	1,000
Paid-in Capital	23,434	23,434
Retained Earnings	27,176	26,038
TOTAL	51,610	50,472
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 370,743	$ 376,703

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 5,148	$ 4,589
Adjustments for Noncash Items:		
Depreciation and Amortization	11,907	11,945
Deferred Income Taxes	(2,298)	(2,379)
Deferred Investment Tax Credits	(1,655)	(1,668)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(2,785)	(2,785)
Deferred Property Taxes	(1,813)	(1,950)
Changes in Other Noncurrent Assets	(456)	(1,270)
Changes in Other Noncurrent Liabilities	579	1,648
Changes in Components of Working Capital:		
Accounts Receivable	2,741	(1,081)
Fuel, Materials and Supplies	(4,213)	4,265
Accounts Payable	(5,242)	(2,405)
Accrued Taxes, Net	3,194	(2,042)
Other Current Assets	(79)	(26)
Other Current Liabilities	91	354
Net Cash Flows From Operating Activities	5,119	7,195
INVESTING ACTIVITIES		
Construction Expenditures	(2,816)	(2,882)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	1,858	(2,294)
Principal Payments for Capital Lease Obligations	(151)	(140)
Dividends Paid	(4,010)	(1,879)
Net Cash Flows Used For Financing Activities	(2,303)	(4,313)
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	$ 1,230	$ 1,063
Cash Paid for Income Taxes, Net of Refunds	3,624	8,080
Noncash Acquisitions Under Capital Leases	74	26

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 SUBSIDIARY

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Allocation Agreement between AEP East companies and AEP West companies

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Therefore, our sharing of margins under the CSW Operating Agreement and the SIA ceased effective May 1, 2006, which affects our future results of operations and cash flows. We will continue to have margin and collateral deposits, risk management assets and liabilities and trading gains or losses to the extent that we have contracts dedicated specifically to us. As of June 30, 2006, we have no dedicated contracts.

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)

Second Quarter of 2005		$ 28
Changes in Gross Margin:		
Texas Supply	(30)	
Texas Wires	8	
Off-system Sales	(2)	
Transmission Revenues	(4)	
Other	(1)	
Total Change in Gross Margin		(29)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	17	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	4	
Other Income (Expense), Net	(1)	
Total Change in Operating Expenses and Other		18
Second Quarter of 2006		$ 17

Net Income decreased $11 million in the second quarter of 2006. The key drivers of the decrease were a $29 million decrease in Gross Margin, partially offset by a reduction in Other Operation and Maintenance expenses of $17 million. We substantially exited the generation market with the sale of STP in May 2005.

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

- Texas Supply margins decreased $30 million primarily due to the sale of STP, which resulted in lower nonaffiliated sales of $38 million, and a $5 million provision for refund primarily due to the fuel reconciliation adjustment in 2005. These decreases were partially offset by lower fuel and purchased power expenses of $12 million.
- Texas Wires revenues increased $8 million primarily due to an increase in sales volumes resulting mainly from a 23% increase in cooling degree days.
- Margins from Off-system Sales decreased $2 million primarily due to lower optimization activities.
- Transmission Revenues decreased $4 million primarily due to lower ERCOT transmission rates and reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $17 million primarily due to a $7 million decrease in power plant operations, a $4 million decrease in plant maintenance and the absence of $3 million in accretion expense all related to the sale of the STP. Customer service and administrative and general expenses decreased $6 million partially offset by increased transmission-related expense of $3 million.
- Taxes Other than Income Taxes decreased $4 million due to the favorable settlement of a state use tax audit in 2006.

Income Taxes

Income Tax Expense remained relatively flat for the second quarter of 2006 compared to the second quarter of 2005.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

Six Months Ended June 30, 2005		$ 30
Changes in Gross Margin:		
Texas Supply	(74)	
Texas Wires	11	
Off-system Sales	(2)	
Transmission Revenues	(9)	
Other	(3)	
Total Change in Gross Margin		(77)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	48	
Depreciation and Amortization	(6)	
Taxes Other Than Income Taxes	6	
Interest Income and Expense, Net	(3)	
Carrying Costs on Stranded Cost Recovery	25	
Total Change in Operating Expenses and Other		70
Income Tax Expense		(2)

Six Months Ended June 30, 2006	$	21

Net Income decreased $9 million in the first six months of 2006. The key drivers of the decrease were a $77 million decrease in Gross Margin, partially offset by a reduction in Other Operation and Maintenance expenses of $48 million and increased Carrying Costs on Stranded Cost Recovery of $25 million. We substantially exited the generation market with the sale of STP in May 2005.

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

- Texas Supply margins decreased $74 million primarily due to the sale of STP which resulted in lower nonaffiliated sales of $98 million and a $6 million provision for refund primarily due to the fuel reconciliation adjustment in 2005. These decreases were partially offset by lower fuel and purchased power expenses of $30 million.
- Texas Wires revenues increased $11 million primarily due to an increase in sales volumes resulting mainly from a 28% increase in cooling degree days.
- Margins from Off-system Sales decreased $2 million primarily due to lower optimization activities.
- Transmission Revenues decreased $9 million primarily due to lower ERCOT transmission rates and reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.
- Other revenues decreased $3 million primarily due to lower third party construction project revenues 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 $48 million primarily due to a $14 million decrease in power plant operations, a $13 million decrease in plant maintenance and the absence of $8 million in accretion expense all related to the sale of STP. An additional $5 million decrease resulted from lower expenses related to construction activities performed for third parties, primarily the Lower Colorado River Authority.
- Depreciation and Amortization expense increased $6 million primarily related to the refund and amortization of excess earnings credits in 2005 partially offset by the recovery and amortization of securitized assets.
- Taxes Other Than Income Taxes decreased $6 million primarily due to lower property-related taxes as a result of the sale of STP in 2005 and the favorable settlement of a state use tax audit in 2006.
- Interest Income and Expense, Net changed unfavorably $3 million primarily due to higher interest on long-term debt and interest related to the Texas competition transition charge liability (See "Texas Restructuring" section of Note 4) partially offset by lower short-term interest expense.
- Carrying Costs on Stranded Cost Recovery increased $25 million primarily due to a $27 million negative adjustment related to prior years, recorded in the first quarter of 2005.

Income Taxes

The increase in Income Tax Expense of $2 million is primarily due to the tax reserve adjustments, a decrease in the amortization of investment tax credits due to the sale in May 2005 of the STP nuclear plant and a decrease in consolidated tax savings from AEP, offset in part by a decrease in pretax book income.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the six months ended June 30, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ -	$ 26
Net Cash Flows From (Used For):		
Operating Activities	81,341	(105,434)
Investing Activities	(121,052)	140,683
Financing Activities	39,711	(33,181)
Net Increase in Cash and Cash Equivalents	-	2,068
Cash and Cash Equivalents at End of Period	$ -	$ 2,094

Operating Activities

Net Cash Flows From Operating Activities were $81 million in the first six months of 2006. We produced Net Income of $21 million during the period and incurred noncash items of $71 million for Depreciation and Amortization and $(40) million for Carrying Costs on Stranded Cost Recovery. 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 most significant are decreases in Accounts Receivable, Net partially offset by a decrease in Accounts Payable. Accounts Receivable, Net decreased $164 million primarily due to cash received for the retail clawback of $61 million and 2005 storm restoration performed for non-affiliated companies of $29 million. In addition, our removal from the SIA and CSW operating agreement resulted in fewer energy-related receivables. Accounts Payable decreased $102 million primarily due to lower energy-related transactions resulting from our removal from the SIA and CSW Operating Agreement.

Net Cash Flows Used For Operating Activities were $105 million in the first six months of 2005. We produced income of $30 million during the period including noncash expense items of $65 million for Depreciation and Amortization and $(83) million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in these asset and liability accounts relate to a number of items; the most significant are decreases in Accounts Payable and Accrued Taxes, offset in part by a decrease in Accounts Receivable, Net. Accounts Payable decreased $46 million while Accounts Receivable decreased $29 million primarily due to energy-related system sales. Accounts Payable also had an additional decrease related to the sale of STP. Accrued Taxes decreased $69 million primarily as a result of taxes remitted to the government related to prior year and current year tax accruals.

Investing Activities

Net Cash Flows Used For Investing Activities in 2006 were $121 million primarily due to $136 million of Construction Expenditures focused on improved service reliability projects for transmission and distribution systems.

Net Cash Flows From Investing Activities in 2005 were $141 million primarily due to $314 million of net proceeds from the sale of the STP nuclear plant. The proceeds were partially offset by an increase of $107 million in Other Cash Deposits, Net related to the issuance of new pollution control revenue bonds, the proceeds which were used specifically for refinancing activities in the third quarter of 2005, and also by Construction Expenditures of $61 million related to projects for improved transmission and distribution service reliability.

For the remainder of 2006, we expect $150 million in Construction Expenditures.

Financing Activities

Net Cash Flows From Financing Activities in 2006 were $40 million primarily due to the issuance of a $125 million affiliated note with AEP. This increase in long-term debt was partially offset by a decrease in Advances from Affiliates, Net of $54 million and the retirement of $31 million of securitization bonds.

Net Cash Flows Used for Financing Activities in 2005 were $33 million primarily due to the retirement of Senior Unsecured Notes Payable and Securitization Bonds of $279 million along with payment of dividends. This was partially offset by a $120 million increase in Advances from Affiliates, Net and issuances of pollution control bonds of $277 million, $120 million of which was issued for the purpose of funding the July 1, 2005 retirement of our $120 million, 6.0% Pollution Control Bonds.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2006 were:

Issuances

Type of Debt		**Principal Amount (in thousands)**	**Interest Rate (%)**	**Due Date**
Notes Payable-Affiliated	$	125,000	5.14	2007

Retirements

Type of Debt		**Principal Amount (in thousands)**	**Interest Rate (%)**	**Due Date**
Securitization Bonds	$	30,641	5.01	2010

In August 2006, an affiliate issued us a 5.86%, $70 million note due August 16, 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.

We will use any proceeds received from the securitization (discussed below under Texas Restructuring) to pay down a portion of our equity and debt.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Texas Restructuring

The PUCT issued an order in our True-up Proceeding in February 2006, which determined that our true-up regulatory asset was $1.475 billion including carrying costs through September 2005. In December 2005, we adjusted our recorded net true-up regulatory asset to comply with the order. We appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties have appealed the PUCT's order claiming it permits us to over-recover stranded costs.

We filed an application in March 2006 requesting to securitize our net stranded generation plant costs and related carrying costs through August 31, 2006. In June 2006, the PUCT approved our settlement with intervenors authorizing the securitization of $1.697 billion of net stranded generation costs including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of $23 million, for a total of $1.72 billion. We anticipate issuing the securitization bonds by the end of the third quarter of 2006.

The differences between the securitization amount ordered by the PUCT of $1.7 billion and the recorded securitizable true-up regulatory asset of $1.5 billion at June 30, 2006 are detailed in the table below:

		(in millions)
Stranded Generation Plant Costs	$	974
Net Generation-related Regulatory Asset		249
Excess Earnings		(49)
Recorded Net Stranded Generation Plant Costs		1,174
Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs		375
Recorded Securitizable True-up Regulatory Asset		1,549
Unrecorded But Recoverable Equity Carrying Costs		217
Unrecorded Estimated July 2006 - August 2006 Debt Carrying Costs		17
Unrecorded Excess Earnings, Related Carrying Costs and Other		52
Settlement Reduction		(77)
Reduction for ADITC and EDFIT Benefits		(61)
Approved Securitizable Amount		1,697
Unrecorded Securitization Issuance Costs		23
Amount to be Securitized	$	1,720

In June 2006, we filed to implement a CTC refund of $355 million for our net other true-up items over eight years. The differences between the components of our Recorded Net Regulatory Liabilities for Other True-up Items as of June 30, 2006 and our CTC proceeding request are detailed below**:**

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		28
Retail Clawback including Carrying Costs		(63)
Deferred Over-recovered Fuel Balance		(181)
Retrospective ADFIT Benefit		(70)
Other		(4)
Recorded Net Regulatory Liabilities - Other True-up Items		(229)
Unrecorded Prospective ADFIT Benefit		(240)
Unrecorded Estimated July 2006 - August 2006 Carrying Costs		(6)
Gross CTC Refund		(475)
FERC Jurisdictional Fuel Refund Deferral		16
ADITC and EDFIT Benefit Refund Deferral		97
Net CTC Refund Proposed, After Deferrals		(362)
Rate Case Expense Surcharge		7
Net Refund Proposed, After Deferrals and Expenses	$	(355)

We requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of $16 million of FERC jurisdictional fuel over-recoveries and $97 million for potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits. Although we proposed to refund the $355 million over eight years, certain intervenors have supported accelerated refunds. Management cannot predict the outcome of this filing. If the two contingent federal matters are resolved unfavorably, we will refund the $16 million and the $97 million plus carrying costs.

Municipal customers and other intervenors are appealing the PUCT orders seeking to further reduce our true-up recoveries. If we determine as a result of future PUCT orders or appeal court rulings that it is probable we cannot recover a portion of our recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. We are appealing the PUCT orders seeking relief in both state and federal court where we believe the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

These appeals could take years to resolve and could result in material effects on future results of operations. If the PUCT rejects our deferral proposal and a normalization violation occurs, future results of operations and cash flows could be adversely affected by the recapture of $105 million of our ADITC and the loss of our future accelerated tax depreciation election. The estimated future impact on earnings of the Texas restructuring as of June 30, 2006, exclusive of a possible normalization violation and any effects of appeal litigation, over the 14-year securitization net recovery period assuming the PUCT approves our CTC filing is detailed below:

		(in millions)
ADITC and EDFIT Benefits Reducing Securitization	$	97

ADFIT Benefit Applied to Reduce 2002 Securitization of Regulatory Assets		(64)
Securitization Settlement		(77)
Unrecorded Prospective ADFIT Benefit Increasing the CTC Refund		(240)
Unrecorded Equity Carrying Costs Recognized as Collected		217
Future Carrying Cost Payable on Proposed CTC Refund		(113)
Deferred Fuel - Federal Jurisdictional Issue		16
Net Adverse Earnings Impact Over 14 Years	$	(164)

If the proposed CTC deferral is rejected by the PUCT or the two contingencies are refunded to customers, the future adverse impact on results of operations over the next 14 years will increase to $317 million. This potential adverse impact on results of operations over the next 14 years would be more than offset by the annual cost of money benefit from the $2.2 billion in net proceeds that resulted from the sale of bonds in connection with the initial regulatory asset securitization in 2002 of $797 million and from the upcoming $1.720 billion sale of securitization bonds later this year less the proposed $355 million CTC refund over the next eight years.

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, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the “Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries” section. An adverse result in these proceedings has 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 2005 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. 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

Our MTM Risk Management Contract Net Assets are zero as of June 30, 2006. For further explanation, see "Allocating Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

The following table summarizes the reasons for changes in our total MTM value as compared to December 31, 2005.

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$	5,426
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(1,362)
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		-
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(3,681)
Changes Due to SIA and CSW Operating Agreement (c)		(383)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		-
Total MTM Risk Management Contract Net Assets		-
Net Cash Flow Hedge Contracts		-
Total MTM Risk Management Contract Net Assets at June 30, 2006	$	-

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek 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) See "Allocating Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

Our net MTM Risk Management Contracts are zero as of June 30, 2006. Therefore, there is no maturity and source of fair value to report.

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 employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

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, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2006
(in thousands)

		Power
Beginning Balance in AOCI December 31, 2005	$	(224)
Changes in Fair Value		-
Impact Due to Changes in SIA (a)		218
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled		6
Ending Balance in AOCI June 30, 2006	$	-

(a) See "Allocating Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is zero.

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 June 30, 2006, 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:

Six Months Ended June 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$-	$11	$3	$-	$111	$184	$88	$32

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 $94 million and $93 million at June 30, 2006 and December 31, 2005, 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 SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2006	**2005**	**2006**	**2005**
REVENUES				
Electric Generation, Transmission and Distribution	$ 149,688	$ 184,743	$ 272,899	$ 366,890
Sales to AEP Affiliates	1,546	5,302	3,144	10,266
Other - Nonaffiliated	10,255	12,281	20,734	26,527
TOTAL	161,489	202,326	296,777	403,683
EXPENSES				
Fuel and Other Consumables for Electric Generation	996	4,034	2,722	10,132
Purchased Electricity for Resale	1,152	9,996	2,832	25,366
Other Operation	63,257	76,584	122,184	157,333
Maintenance	8,787	12,433	16,576	29,472
Depreciation and Amortization	37,215	35,434	70,550	64,720
Taxes Other Than Income Taxes	16,671	20,923	37,034	43,454
TOTAL	128,078	159,404	251,898	330,477
OPERATING INCOME	33,411	42,922	44,879	73,206
Other Income (Expense):				
Interest Income	527	5,929	1,032	7,427
Carrying Costs Income	20,413	19,938	39,836	14,797
Allowance for Equity Funds Used During Construction	631	149	1,004	700
Interest Expense	(29,882)	(32,642)	(56,655)	(59,721)
INCOME BEFORE INCOME TAXES	25,100	36,296	30,096	36,409
Income Tax Expense	8,125	7,928	9,348	6,904
NET INCOME	16,975	28,368	20,748	29,505
Preferred Stock Dividend Requirements	61	61	121	121
EARNINGS APPLICABLE TO COMMON STOCK	$ 16,914	$ 28,307	$ 20,627	$ 29,384

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 SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 55,292	$ 132,606	$ 1,084,904	$ (4,159)	$ 1,268,643
Common Stock Dividends			(150,000)		(150,000)
Preferred Stock Dividends			(121)		(121)
TOTAL					1,118,522
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $546				(1,014)	(1,014)
NET INCOME			29,505		29,505
TOTAL COMPREHENSIVE INCOME					28,491
JUNE 30, 2005	$ 55,292	$ 132,606	$ 964,288	$ (5,173)	$ 1,147,013
DECEMBER 31, 2005	$ 55,292	$ 132,606	$ 760,884	$ (1,152)	$ 947,630
Preferred Stock Dividends			(121)		(121)
TOTAL					947,509
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $121				224	224
NET INCOME			20,748		20,748
TOTAL COMPREHENSIVE INCOME					20,972
JUNE 30, 2006	$ 55,292	$ 132,606	$ 781,511	$ (928)	$ 968,481

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ -
Other Cash Deposits	57,456	66,153
Accounts Receivable:		
Customers	64,155	209,957
Affiliated Companies	4,002	23,486
Accrued Unbilled Revenues	26,481	25,606
Allowance for Uncollectible Accounts	(185)	(143)
Total Accounts Receivable	94,453	258,906
Unbilled Construction Costs	13,177	19,440
Materials and Supplies	20,951	13,897
Risk Management Assets	-	14,311
Prepayments and Other	6,822	5,231
TOTAL	192,859	377,938
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	892,979	817,351
Distribution	1,543,035	1,476,683
Other	229,915	233,361
Construction Work in Progress	97,407	129,800
Total	2,763,336	2,657,195
Accumulated Depreciation and Amortization	627,669	636,078
TOTAL - NET	2,135,667	2,021,117
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,688,536	1,688,787
Securitized Transition Assets	572,157	593,401
Long-term Risk Management Assets	-	11,609
Employee Benefits and Pension Assets	113,299	114,733
Deferred Charges and Other	67,292	53,011
TOTAL	2,441,284	2,461,541
Assets Held for Sale - Texas Generation Plants	45,608	44,316
TOTAL ASSETS	$ 4,815,418	$ 4,904,912

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 27,926	$ 82,080
Accounts Payable:		
General	32,661	82,666
Affiliated Companies	16,960	65,574
Long-term Debt Due Within One Year - Nonaffiliated	154,384	152,900
Risk Management Liabilities	-	13,024
Accrued Taxes	50,221	54,566
Accrued Interest	31,767	32,497
Other	26,606	45,927
TOTAL	340,525	529,234
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	1,518,580	1,550,596
Long-term Debt - Affiliated	275,000	150,000
Long-term Risk Management Liabilities	-	7,857
Deferred Income Taxes	1,014,520	1,048,372
Regulatory Liabilities and Deferred Investment Tax Credits	674,269	652,143
Deferred Credits and Other	18,104	13,140
TOTAL	3,500,473	3,422,108
TOTAL LIABILITIES	3,840,998	3,951,342
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,939	5,940
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $25 Par Value 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	781,511	760,884
Accumulated Other Comprehensive Income (Loss)	(928)	(1,152)
TOTAL	968,481	947,630
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,815,418	$ 4,904,912

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 20,748	$ 29,505
Adjustments for Noncash Items:		
Depreciation and Amortization	70,550	64,720
Accretion of Asset Retirement Obligations	37	7,549
Deferred Income Taxes	6,095	(83,369)
Carrying Costs on Stranded Cost Recovery	(39,836)	(14,797)
Mark-to-Market of Risk Management Contracts	5,426	7,085
Over/Under Fuel Recovery	3,908	(2,400)
Deferred Property Taxes	(16,592)	(15,450)
Change in Other Noncurrent Assets	21,686	(1,908)
Change in Other Noncurrent Liabilities	(25,338)	9
Changes in Components of Working Capital:		
Accounts Receivable, Net	164,453	28,976
Fuel, Materials and Supplies	(7,652)	(969)
Accounts Payable	(102,422)	(45,594)
Accrued Taxes, Net	(9,596)	(69,046)
Customer Deposits	(6,876)	(733)
Accrued Interest	(730)	(2,555)
Other Current Assets	9,924	(8,279)
Other Current Liabilities	(12,444)	1,822
Net Cash Flows From (Used For) Operating Activities	81,341	(105,434)
INVESTING ACTIVITIES		
Construction Expenditures	(136,475)	(60,972)
Change in Other Cash Deposits, Net	9,340	(107,494)
Purchases of Investment Securities	-	(154,364)
Sales of Investment Securities	-	149,804
Proceeds from Sale of Assets	6,083	313,709
Net Cash Flows From (Used For) Investing Activities	(121,052)	140,683
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	-	276,690
Issuance of Long-term Debt - Affiliated	125,000	-
Change in Advances from Affiliates, Net	(54,154)	119,857
Retirement of Long-term Debt	(30,641)	(279,386)
Retirement of Preferred Stock	(1)	-
Principal Payments for Capital Lease Obligations	(372)	(221)
Dividends Paid on Cumulative Preferred Stock	(121)	(121)
Dividends Paid on Common Stock	-	(150,000)
Net Cash From (Used For) Financing Activities	39,711	(33,181)

Net Increase in Cash and Cash Equivalents		-		2,068
Cash and Cash Equivalents at Beginning of Period		-		26
Cash and Cash Equivalents at End of Period	$	-	$	2,094
SUPPLEMENTAL DISCLOSURE				
Cash Paid for Interest, Net of Capitalized Amounts	$	51,577	$	52,441
Cash Paid for Income Taxes, Net of Refunds		13,440		161,372
Noncash Acquisitions Under Capital Leases		2,145		261
Construction Expenditures Included in Accounts Payable at June 30,		14,840		3,970

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries .

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
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

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

Allocation Agreement between AEP East companies and AEP West companies

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Therefore, our sharing of margins under the CSW Operating Agreement and the SIA ceased effective May 1, 2006, which affects our future results of operations and cash flows. We will continue to have margin and collateral deposits, risk management assets and liabilities and trading gains or losses to the extent that we have contracts dedicated specifically to us.

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income (Loss)
(in millions)

Second Quarter of 2005		$	12
Changes in Gross Margin:			
Texas Supply	(14)		
Texas Wires	(1)		
Off-system Sales	(2)		
Transmission Revenues	(3)		
Other	(3)		
Total Change in Gross Margin			(23)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance			3
Income Tax Expense			7
Second Quarter of 2006		$	(1)

Net Income decreased $13 million in the second quarter of 2006 primarily due to a decrease in Gross Margin of $23 million partially offset by a reduction in Other Operation and Maintenance expenses of $3 million.

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

- Texas Supply margins decreased $14 million primarily due to a $19 million decrease in dedicated ERCOT energy sales, offset by $9 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by increased generation outages and market conditions within ERCOT.

- Transmission Revenues decreased $3 million primarily due to reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.
- Other revenues decreased $3 million primarily due to the completion of certain third party construction projects, primarily 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 $3 million primarily due to lower expenses related to the completion of certain third party construction projects, primarily related to work performed for the Lower Colorado River Authority.

Income Taxes

The decrease in Income Tax Expense of $7 million is primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

Six Months Ended June 30, 2005		$ 19
Changes in Gross Margin:		
Texas Supply	(17)	
Texas Wires	(1)	
Off-system Sales	(1)	
Transmission Revenues	(5)	
Other	(40)	
Total Change in Gross Margin		(64)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	37	
Interest Expense	1	
Total Change in Operating Expenses and Other		38
Income Tax Expense		10
Six Months Ended June 30, 2006		$ 3

Net Income decreased $16 million in the first six months of 2006 primarily due to a decrease in Gross Margin of $64 million partially offset by a reduction in Other Operation and Maintenance expenses of $37 million.

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

- Texas Supply margins decreased $17 million primarily due to a $25 million decrease in dedicated ERCOT energy sales, offset by $12 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by increased generation outages and market conditions within ERCOT.

- Transmission Revenues decreased $5 million primarily due to reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.
- Other revenues decreased $40 million primarily resulting from the completion of certain third party construction projects, primarily 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 $37 million primarily due to lower expenses related to the completion of certain third party construction projects, primarily related to work performed for the Lower Colorado River Authority.

Income Taxes

The decrease in Income Tax Expense of $10 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook, except for Fitch which moved us to negative outlook. Our current ratings are as follows:

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

Financing Activity

There were no long-term debt issuances or retirements during the first six months of 2006.

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 2005 Annual Report and has not changed significantly from year-end except for Energy and Capacity Purchase Contracts. We exited both the SIA and CSW Operating Agreement eliminating our future obligation in Energy and Capacity Purchase Contracts. See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section within Note 3 - Rate Matters.

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, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has 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 2005 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. 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 balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Condensed Balance Sheet As of June 30, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ -	$ 552	$ 552
Noncurrent Assets	-	4,027	4,027
Total MTM Derivative Contract Assets	-	4,579	4,579
Current Liabilities	-	(843)	(843)
Noncurrent Liabilities	-	-	-
Total MTM Derivative Contract Liabilities	-	(843)	(843)
Total MTM Derivative Contract Net Assets	$ -	$ 3,736	$ 3,736

MTM Risk Management Contract Net Assets Six Months Ended June 30, 2006 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 2,698
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(678)
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)	(1,206)
Changes Due to SIA and CSW Operating Agreement (c)	(814)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	-
Total MTM Risk Management Contract Net Assets	-
Net Cash Flow Hedge Contracts	3,736
Total MTM Risk Management Contract Net Assets at June 30, 2006	$ 3,736

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek 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) See "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

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

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

Our MTM Risk Management Contract Net Assets are zero as of June 30, 2006. Therefore, there is no Maturity and Source of Fair Value to report.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Condensed 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 employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2006
(in thousands)

		Power
Beginning Balance in AOCI December 31, 2005	$	(111)
Changes in Fair Value		2,429
Impact Due to Change in SIA (a)		98
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled		13
Ending Balance in AOCI June 30, 2006	$	2,429

(a) See "Allocating Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $189 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 June 30, 2006, 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:

Six Months Ended June 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$-	$23	$6	$-	$55	$92	$44	$16

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 $15 million and $13 million at June 30, 2006 and December 31, 2005, 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
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended 2006	Three Months Ended 2005	Six Months Ended 2006	Six Months Ended 2005
REVENUES				
Electric Generation, Transmission and Distribution	$ 71,051	$ 97,199	$ 139,876	$ 169,088
Sales to AEP Affiliates	11,860	12,880	17,885	24,170
Other	87	4,625	(97)	40,353
TOTAL	82,998	114,704	157,664	233,611
EXPENSES				
Fuel and Other Consumables for Electric Generation	7,044	11,356	19,159	24,339
Purchased Electricity for Resale	32,883	37,604	47,279	53,964
Other Operation	21,633	24,587	40,189	78,257
Maintenance	5,216	4,920	10,417	9,139
Depreciation and Amortization	10,182	10,362	20,405	20,517
Taxes Other Than Income Taxes	5,856	5,713	11,396	11,418
TOTAL	82,814	94,542	148,845	197,634
OPERATING INCOME	184	20,162	8,819	35,977
Other Income (Expense):				
Interest Income	120	542	339	798
Allowance for Equity Funds Used During Construction	108	156	490	229
Interest Expense	(4,517)	(4,869)	(8,879)	(9,853)
INCOME (LOSS) BEFORE INCOME TAXES	(4,105)	15,991	769	27,151
Income Tax Expense (Credit)	(3,513)	3,987	(2,473)	7,753
NET INCOME (LOSS)	(592)	12,004	3,242	19,398
Preferred Stock Dividend Requirements	26	26	52	52
Gain on Reacquired Preferred Stock	-	-	2	-
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ (618)	$ 11,978	$ 3,192	$ 19,346

T *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
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$ 310,421
Common Stock Dividends			(12,626)		(12,626)
Preferred Stock Dividends			(52)		(52)
TOTAL					297,743
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $236				(439)	(439)
NET INCOME			19,398		19,398
TOTAL COMPREHENSIVE INCOME					18,959
JUNE 30, 2005	$ 137,214	$ 2,351	$ 177,704	$ (567)	$ 316,702
DECEMBER 31, 2005	$ 137,214	$ 2,351	$ 174,858	$ (504)	$ 313,919
Common Stock Dividends			(12,750)		(12,750)
Preferred Stock Dividends			(52)		(52)
Gain on Reacquired Preferred Stock			2		2
TOTAL					301,119
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,368				2,540	2,540
NET INCOME			3,242		3,242
TOTAL COMPREHENSIVE INCOME					5,782
JUNE 30, 2006	$ 137,214	$ 2,351	$ 165,300	$ 2,036	$ 306,901

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ -
Other Cash Deposits	8,993	1,432
Advances to Affiliates	-	34,286
Accounts Receivable:		
Customers	24,702	77,678
Affiliated Companies	8,176	26,149
Accrued Unbilled Revenues	4,383	5,016
Allowance for Uncollectible Accounts	(23)	(18)
Total Accounts Receivable	37,238	108,825
Fuel	7,000	2,636
Materials and Supplies	7,743	6,858
Risk Management Assets	552	7,114
Prepayments and Other	3,665	3,772
TOTAL	65,191	164,923
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	290,261	288,934
Transmission	324,294	289,029
Distribution	502,917	492,878
Other	164,500	167,849
Construction Work in Progress	23,223	46,424
Total	1,305,195	1,285,114
Accumulated Depreciation and Amortization	479,043	478,519
TOTAL - NET	826,152	806,595
OTHER NONCURRENT ASSETS		
Regulatory Assets	9,078	9,787
Long-term Risk Management Assets	4,027	5,772
Employee Benefits and Pension Assets	45,702	46,289
Deferred Charges and Other	10,930	10,468
TOTAL	69,737	72,316
TOTAL ASSETS	$ 961,080	$ 1,043,834

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 6,005	$ -
Accounts Payable:		
General	13,767	19,739
Affiliated Companies	27,450	84,923
Long-term Debt Due Within One Year - Nonaffiliated	8,151	-
Risk Management Liabilities	843	6,475
Accrued Taxes	19,904	21,212
Other	11,926	21,050
TOTAL	88,046	153,399
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	268,739	276,845
Long-term Risk Management Liabilities	-	3,906
Deferred Income Taxes	127,114	132,335
Regulatory Liabilities and Deferred Investment Tax Credits	146,653	139,732
Deferred Credits and Other	21,278	21,341
TOTAL	563,784	574,159
TOTAL LIABILITIES	651,830	727,558
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,349	2,357
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $25 Par Value 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	165,300	174,858
Accumulated Other Comprehensive Income (Loss)	2,036	(504)
TOTAL	306,901	313,919
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 961,080	$ 1,043,834

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

		2006		2005
OPERATING ACTIVITIES				
Net Income	$	3,242	$	19,398
Adjustments for Noncash Items:				
Depreciation and Amortization		20,405		20,517
Deferred Income Taxes		(3,183)		(1,742)
Mark-to-Market of Risk Management Contracts		2,698		3,062
Deferred Property Taxes		(8,408)		(8,145)
Change in Other Noncurrent Assets		(3,302)		(1,937)
Change in Other Noncurrent Liabilities		1,904		2,202
Changes in Components of Working Capital:				
Accounts Receivable, Net		71,587		4,654
Fuel, Materials and Supplies		(5,249)		(2,495)
Accounts Payable		(62,323)		11,893
Accrued Taxes, Net		(4,046)		(11,847)
Customer Deposits		(3,571)		(388)
Other Current Assets		2,845		14,577
Other Current Liabilities		(4,582)		(710)
Net Cash Flows From Operating Activities		8,017		49,039
INVESTING ACTIVITIES				
Construction Expenditures		(36,675)		(24,177)
Change in Other Cash Deposits, Net		1,073		-
Change In Advances to Affiliates, Net		34,286		(12,161)
Proceeds from Sale of Assets		250		1,033
Net Cash Flows Used For Investing Activities		(1,066)		(35,305)
FINANCING ACTIVITIES				
Change in Advances from Affiliates, Net		6,005		-
Retirement of Preferred Stock		(6)		-
Principal Payments for Capital Lease Obligations		(148)		(118)
Dividends Paid on Common Stock		(12,750)		(12,626)
Dividends Paid on Cumulative Preferred Stock		(52)		(52)
Net Cash Flows Used For Financing Activities		(6,951)		(12,796)
Net Increase in Cash and Cash Equivalents		-		938
Cash and Cash Equivalents at Beginning of Period		-		-
Cash and Cash Equivalents at End of Period	$	-	$	938
SUPPLEMENTAL DISCLOSURE				
Cash Paid for Interest, Net of Capitalized Amounts	$	7,809	$	9,014
Cash Paid for Income Taxes, Net of Refunds		6,079		21,865
Noncash Acquisitions Under Capital Leases		749		171
		2,037		1,726

Construction Expenditures Included in Accounts
Payable at June 30,

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
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

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income (in millions)

Second Quarter of 2005		$ 24
Changes in Gross Margin:		
Retail Margins	5	
Off-system Sales	1	
Transmission Revenues	(17)	
Other	(1)	
Total Change in Gross Margin		(12)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(10)	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	1	
Carrying Costs Income	4	
Interest Expense	(4)	
Other Income	4	
Total Change in Operating Expenses and Other		(7)
Income Tax Expense		5
Second Quarter of 2006		$ 10

Net Income decreased $14 million to $10 million in 2006. The key drivers of the decrease were a $12 million net decrease in Gross Margin and a $7 million net increase in Operating Expenses and Other, offset by a $5 million decrease in Income Tax Expense.

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 $5 million in comparison to 2005 primarily due to an $8 million reduction in capacity settlement payments under the Interconnection Agreement due to our lower member load ratio (MLR) share and our increased capacity, an $8 million increase in revenues related to financial transmission rights, net of congestion, and a $7 million increase in retail revenues primarily related to two new industrial customers. The increase in financial transmission rights revenue is due to improved management of price risk related to serving retail load under current transmission constraints. These increases were partially offset by a $15 million decline in fuel margins caused primarily by higher fuel costs.
-

Transmission Revenues decreased $17 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a $5 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the “SECA Revenue Subject to Refund” section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $10 million mainly due to a $5 million increase in planned maintenance outages and an increase of $4 million related to increased expenses for overhead line right-of-way clearing and overhead line repairs.
- Carrying Costs Income increased $4 million primarily due to the establishment of a regulatory asset for carrying costs related to the Virginia environmental and reliability costs incurred.
- Interest Expense increased $4 million primarily due to long-term debt issuances in 2006, partially offset by an increase in allowance for borrowed funds used during construction.
- Other Income increased $4 million primarily due to interest income related to an increase in Advances to Affiliates.

Income Taxes

The decrease in Income Tax Expense of $5 million is primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by an increase in state income taxes.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

Six Months Ended June 30, 2005		$ 71
Changes in Gross Margin:		
Retail Margins	33	
Transmission Revenues	(16)	
Other	1	
Total Change in Gross Margin		18
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	3	
Taxes Other Than Income Taxes	2	
Carrying Costs Income	10	
Interest Expense	(11)	
Other Income	4	
Total Change in Operating Expenses and Other		8
Income Tax Expense		(14)
Six Months Ended June 30, 2006		$ 83

Net Income increased $12 million to $83 million in 2006. The key drivers of the increase were an $18 million net increase in Gross Margin and an $8 million net decrease in Operating Expenses and Other, offset by a $14 million increase in Income Tax Expense.

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 $33 million in comparison to 2005 primarily due to a $24 million increase in revenues related to financial transmission rights, net of congestion, a $17 million increase in retail revenues primarily related to two new industrial customers and a $12 million reduction in capacity settlement payments under the Interconnection Agreement due to our lower MLR share and our increased capacity. These increases were partially offset by a $14 million decline in fuel margins caused primarily by higher fuel costs.
- Transmission Revenues decreased $16 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a $5 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

- Carrying Costs Income increased $10 million primarily due to the establishment of a regulatory asset for carrying costs related to the Virginia environmental and reliability costs incurred.
- Interest Expense increased $11 million primarily due to long-term debt issuances in 2006, partially offset by an increase in allowance for borrowed funds used during construction.
- Other Income increased $4 million primarily due to interest income related to an increase in Advances to Affiliates.

Income Taxes

The increase in Income Tax Expense of $14 million is primarily due to an increase 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
Senior Unsecured Debt	Baa2	BBB	BBB+

Cash Flow

Cash flows for the six months ended June 30, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,741	$ 1,543
Net Cash Flows From (Used For):		
Operating Activities	320,554	87,588

Investing Activities	(622,504)	(269,487)
Financing Activities	301,555	181,637
Net Decrease in Cash and Cash Equivalents	(395)	(262)
Cash and Cash Equivalents at End of Period	$ 1,346	$ 1,281

Operating Activities

Net Cash Flows From Operating Activities were $321 million in 2006. We produced Net Income of $83 million during the period and a noncash expense item of $96 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 included two significant items. We had a decrease of $60 million in Accounts Receivable, Net due to the collection of receivables related to power sales to affiliates, settled litigation and sales on emission allowances. We had an increase of $42 million in Accrued Taxes, Net related to the lack of federal income tax payments made in 2006.

Net Cash Flows From Operating Activities were $88 million in 2005. We produced income of $71 million during the period and a noncash expense item of $96 million for Depreciation and Amortization partially offset by Pension Contributions to Qualified Plan Trusts of $40 million. 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.

Investing Activities

Net Cash Flows Used For Investing Activities during 2006 and 2005 primarily reflect our construction expenditures of $404 million and $277 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 and 2005, capital projects for transmission expenditures primarily relate to the Wyoming-Jacksons Ferry 765 kV line placed in service in June 2006. Environmental upgrades include the flue gas desulphurization (FGD) projects at the Amos and Mountaineer Plants. For the remainder of 2006, we expect $530 million of construction expenditures. In addition, we invested $219 million into the Utility Money Pool, in 2006.

Financing Activities

Net Cash Flows From Financing Activities were $302 million in 2006. We issued $500 million in senior notes and issued $50 million in pollution control bonds. We also retired a First Mortgage Bond of $100 million. We repaid short-term borrowings from the Utility Money Pool of $194 million. In addition, we received funds of $68 million related to a long-term coal purchase contract amended in March 2006. See “Coal Contract Amendment” within “Significant Factors” for additional information.

Net Cash Flows From Financing Activities were $182 million in 2005. We issued three Senior Unsecured Notes totaling $600 million. We also issued Notes Payable - Affiliates of $100 million and received a capital contribution from our parent of $100 million. We retired $450 million of Senior Unsecured Notes and three First Mortgage Bonds totaling $125 million. In addition, we repaid $34 million of advances from the Utility Money Pool.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2006 were:

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$	50,275	Variable	2036
Senior Unsecured Notes		250,000	5.55	2011
Senior Unsecured Notes		250,000	6.375	2036

Retirements

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
First Mortgage Bonds	$	100,000	6.80	2006
Other Debt		5	13.718	2026

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 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed above.

Significant Factors

Coal Contract Amendment

We negotiated an amendment to a nonderivative coal contract that was assigned to a new owner of a coal supplier to which we were contractually obligated. The amended contract includes adjustments in the quantity related to the shortfall of tons in prior years, escalated tonnage deliveries in 2006 and a pricing change related to future coal deliveries. In March 2006, the new owner agreed to pay us $80 million for the settlement, release and amendment of the original contract. With respect to prior years' undelivered coal, the new owner paid us $12 million for the shortfall tons. With respect to deliveries of coal in 2006-2007, the third party paid us the remaining $68 million for the agreed upon price increase.

The receipt of funds reduces the risk that the third party will short future deliveries. However, if they fail to deliver, we are not contractually obligated to repay any portion of the settlement payment. Our net coal price will not materially change from the original contract price as a result of the $68 million payment that we received for future coal deliveries through 2007.

Since there are no further requirements related to the liquidation of the shortfall tons, we recognized the $12 million shortfall payment in the first quarter of 2006. We recorded a $5 million reduction in Regulatory Assets on our Condensed Consolidated Balance Sheet and recorded the remaining $7 million as a reduction to Fuel and Other Consumables for Electric Generation on our Condensed Consolidated Statement of Income. We recorded the $68 million payment within Deferred Credits and Other on our Condensed Consolidated Balance Sheet. To the extent tons are received, payment of the higher contracted price per ton will effectively result in a repayment of funds to the coal supplier.

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, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters and Note 5 - Commitments and Contingencies in the “Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries” section. An adverse result in these proceedings has 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 2005 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. 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 June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of June 30, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 71,996	$ 18,587	$ -	$ 90,583
Noncurrent Assets	126,964	989	-	127,953
Total MTM Derivative Contract Assets	198,960	19,576	-	218,536
Current Liabilities	(54,973)	(4,849)	(1,610)	(61,432)
Noncurrent Liabilities	(88,104)	(936)	(10,331)	(99,371)
Total MTM Derivative Contract Liabilities	(143,077)	(5,785)	(11,941)	(160,803)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 55,883	$ 13,791	$ (11,941)	$ 57,733

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

MTM Risk Management Contract Net Assets Six Months Ended June 30, 2006 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 56,407
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(4,766)
Fair Value of New Contracts at Inception When Entered During the Period (a)	137
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(1,234)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	359
Changes in Fair Value Due to Market Fluctuations During the Period (b)	4,968
Changes due to SIA Agreement (c)	(6,533)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	6,545

Total MTM Risk Management Contract Net Assets		55,883
Net Cash Flow & Fair Value Hedge Contracts		13,791
DETM Assignment (e)		(11,941)
Total MTM Risk Management Contract Net Assets at June 30, 2006	$	57,733

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 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 giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of June 30, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted - Exchange Traded Contracts	$ (3,470)	$ 3,878	$ 3,971	$ -	$ -	$ -	$ 4,379
Prices Provided by Other External Sources - OTC Broker Quotes (a)	11,195	10,112	3,861	7,480	-	-	32,648
Prices Based on Models and Other Valuation Methods (b)	276	450	2,585	4,118	8,704	2,723	18,856
Total	$ 8,001	$ 14,440	$ 10,417	$ 11,598	$ 8,704	$ 2,723	$ 55,883

(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.

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 employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate forward and swap transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been 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, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2006
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (1,480)	$ (171)	$ (14,770)	$ (16,421)
Changes in Fair Value	10,987	-	4,951	15,938
Impact due to Changes in SIA (a)	(442)	-	-	(442)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	1,089	3	1,410	2,502
Ending Balance in AOCI June 30, 2006	$ 10,154	$ (168)	$ (8,409)	$ 1,577

(a) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $7,941 thousand gain.

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 June 30, 2006, 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:

Six Months Ended June 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$685	$1,604	$695	$401	$732	$1,216	$579	$209

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 $178 million and $142 million at June 30, 2006 and December 31, 2005, 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 and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended 2006	Three Months Ended 2005	Six Months Ended 2006	Six Months Ended 2005
REVENUES				
Electric Generation, Transmission and Distribution	$ 464,058	$ 436,343	$ 1,024,051	$ 912,370
Sales to AEP Affiliates	48,608	58,927	120,380	138,097
Other	1,922	1,832	4,598	4,330
TOTAL	514,588	497,102	1,149,029	1,054,797
EXPENSES				
Fuel and Other Consumables for Electric Generation	155,240	125,759	322,093	240,903
Purchased Electricity for Resale	29,979	26,732	57,595	54,965
Purchased Electricity from AEP Affiliates	103,457	107,023	225,856	233,986
Other Operation	77,458	76,722	147,655	150,495
Maintenance	46,668	37,266	84,507	84,456
Depreciation and Amortization	48,386	46,491	96,358	96,450
Taxes Other Than Income Taxes	22,799	23,357	45,891	47,431
TOTAL	483,987	443,350	979,955	908,686
OPERATING INCOME	30,601	53,752	169,074	146,111
Other Income (Expense):				
Interest Income	2,814	443	3,765	1,005
Carrying Costs Income	7,773	3,967	13,784	4,065
Allowance for Equity Funds Used During Construction	4,083	2,557	6,559	4,768
Interest Expense	(31,653)	(27,145)	(61,921)	(51,344)
INCOME BEFORE INCOME TAXES	13,618	33,574	131,261	104,605
Income Tax Expense	3,971	9,361	48,020	33,720
NET INCOME	9,647	24,213	83,241	70,885
Preferred Stock Dividend Requirements Including Capital Stock Expense and Other	238	905	476	1,702
EARNINGS APPLICABLE TO COMMON STOCK	$ 9,409	$ 23,308	$ 82,765	$ 69,183

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 Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 260,458	$ 722,314	$ 508,618	$ (81,672)	$ 1,409,718
Capital Contribution From Parent		100,000			100,000
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense and Other		2,447	(1,302)		1,145
TOTAL					1,510,463
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,474				(13,882)	(13,882)
NET INCOME			70,885		70,885
TOTAL COMPREHENSIVE INCOME					57,003
JUNE 30, 2005	$ 260,458	$ 824,761	$ 577,801	$ (95,554)	$ 1,567,466
DECEMBER 31, 2005	$ 260,458	$ 924,837	$ 635,016	$ (16,610)	$ 1,803,701
Common Stock Dividends			(5,000)		(5,000)
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense and Other		80	(76)		4
TOTAL					1,798,305
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $9,692				17,998	17,998
NET INCOME			83,241		83,241
TOTAL COMPREHENSIVE INCOME					101,239
JUNE 30, 2006	$ 260,458	$ 924,917	$ 712,781	$ 1,388	$ 1,899,544

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,346	$ 1,741
Advances to Affiliates	218,702	-
Accounts Receivable:		
Customers	168,893	141,810
Affiliated Companies	86,461	153,453
Accrued Unbilled Revenues	30,571	51,201
Miscellaneous	3,658	527
Allowance for Uncollectible Accounts	(4,742)	(1,805)
Total Accounts Receivable	284,841	345,186
Fuel	72,947	64,657
Materials and Supplies	55,288	54,967
Risk Management Assets	90,583	132,247
Accrued Tax Benefits	-	32,979
Prepayments and Other	37,559	75,129
TOTAL	761,266	706,906
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,826,293	2,798,157
Transmission	1,585,714	1,266,855
Distribution	2,202,696	2,141,153
Other	337,359	323,158
Construction Work in Progress	593,062	647,638
Total	7,545,124	7,176,961
Accumulated Depreciation and Amortization	2,556,021	2,524,855
TOTAL - NET	4,989,103	4,652,106
OTHER NONCURRENT ASSETS		
Regulatory Assets	452,651	457,294
Long-term Risk Management Assets	127,953	176,231
Deferred Charges and Other	252,291	261,556
TOTAL	832,895	895,081
TOTAL ASSETS	$ 6,583,264	$ 6,254,093

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 194,133
Accounts Payable:		
General	276,383	230,570
Affiliated Companies	78,307	85,941
Long-term Debt Due Within One Year - Nonaffiliated	171,645	146,999
Risk Management Liabilities	61,432	121,165
Customer Deposits	55,030	79,854
Accrued Taxes	59,211	49,833
Other	113,883	108,746
TOTAL	815,891	1,017,241
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	2,325,465	1,904,379
Long-term Debt - Affiliated	100,000	100,000
Long-term Risk Management Liabilities	99,371	147,117
Deferred Income Taxes	943,008	952,497
Regulatory Liabilities and Deferred Investment Tax Credits	208,725	201,230
Deferred Credits and Other	173,494	110,144
TOTAL	3,850,063	3,415,367
TOTAL LIABILITIES	4,665,954	4,432,608
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,766	17,784
Commitments and Contingencies (Note 5)		
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	924,917	924,837
Retained Earnings	712,781	635,016
Accumulated Other Comprehensive Income (Loss)	1,388	(16,610)
TOTAL	1,899,544	1,803,701
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,583,264	$ 6,254,093

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 83,241	$ 70,885
Adjustments for Noncash Items:		
Depreciation and Amortization	96,358	96,450
Deferred Income Taxes	(1,466)	18,206
Carrying Costs Income	(13,784)	(4,065)
Mark-to-Market of Risk Management Contracts	147	(13,473)
Pension Contributions to Qualified Plan Trusts	-	(39,875)
Over/Under Fuel Recovery, Net	3,636	(8,759)
Change in Other Noncurrent Assets	9,872	(11,224)
Change in Other Noncurrent Liabilities	17,986	(20,276)
Changes in Components of Working Capital:		
Accounts Receivable, Net	60,345	16,710
Fuel, Materials and Supplies	(8,611)	(25,875)
Margin Deposits	27,872	(4,899)
Accounts Payable	14,993	36,157
Customer Deposits	(24,824)	15,447
Accrued Taxes, Net	42,357	(29,847)
Other Current Assets	7,295	(4,394)
Other Current Liabilities	5,137	(3,580)
Net Cash Flows From Operating Activities	320,554	87,588
INVESTING ACTIVITIES		
Construction Expenditures	(404,252)	(277,177)
Change in Other Cash Deposits, Net	-	(41)
Change in Advances to Affiliates, Net	(218,702)	-
Proceeds from Sales of Assets	450	7,731
Net Cash Flows Used For Investing Activities	(622,504)	(269,487)
FINANCING ACTIVITIES		
Capital Contributions from Parent	-	100,000
Issuance of Long-term Debt - Nonaffiliated	544,364	594,717
Issuance of Long-term Debt - Affiliated	-	100,000
Change in Advances from Affiliates, Net	(194,133)	(34,368)
Retirement of Long-term Debt - Nonaffiliated	(100,005)	(575,005)
Retirement of Preferred Stock	(14)	-
Principal Payments for Capital Lease Obligations	(2,768)	(3,307)
Funds From Amended Coal Contract, Net	59,511	-
Dividends Paid on Common Stock	(5,000)	-
Dividends Paid on Cumulative Preferred Stock	(400)	(400)
Net Cash Flows From Financing Activities	301,555	181,637
Net Decrease in Cash and Cash Equivalents	(395)	(262)

Cash and Cash Equivalents at Beginning of Period		1,741		1,543
Cash and Cash Equivalents at End of Period	$	1,346	$	1,281
SUPPLEMENTAL DISCLOSURE				
Cash Paid for Interest, Net of Capitalized Amounts	$	51,558	$	45,064
Cash Paid for Income Taxes, Net of Refunds		4,562		47,461
Noncash Acquisitions Under Capital Leases		2,287		748
Construction Expenditures Included in Accounts Payable at June 30,		105,826		36,339

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

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)

Second Quarter of 2005		$	35
Changes in Gross Margin:			
Retail Margins	32		
Off-system Sales	2		
Transmission Revenues	(9)		
Other	2		
Total Change in Gross Margin			27
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(1)		
Depreciation and Amortization	(19)		
Taxes Other Than Income Taxes	(9)		
Carrying Costs Income	(3)		
Interest Expense	(2)		
Total Change in Operating Expenses and Other			(34)
Income Tax Expense			4
Second Quarter of 2006		$	32

Net Income remained relatively flat in the second quarter of 2006 compared to the second quarter of 2005.

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

- Retail Margins were $32 million higher than the prior period primarily due to Rate Stabilization Plan (RSP) and Transition Regulatory Asset rate increases effective January 1, 2006 as well as the addition of Monongahela Power's Ohio customers on December 31, 2005, partially offset by an increase in delivered fuel costs.
- Transmission Revenues decreased $9 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a $3 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

·

Depreciation and Amortization expense increased $19 million due to the 2005 RSP order that resulted in the reversal of unused shopping credits of $18 million partially offset by the establishment of a $7 million regulatory liability to benefit low-income customers and for economic development. Depreciation expense also increased due to a greater depreciable base resulting primarily from the acquisitions of the Waterford Plant and Monongahela Power's Ohio assets in the second half of 2005.

- Taxes Other Than Income Taxes increased $9 million due to an increase in real and personal property taxes.

Income Tax

The decrease of $4 million in Income Tax Expense is primarily due to a decrease in pretax book income and state income taxes.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income
(in millions)

Six Months Ended June 30, 2005		$	82
Changes in Gross Margin:			
Retail Margins	56		
Off-system Sales	9		
Transmission Revenues	(7)		
Other	9		
Total Change in Gross Margin			67
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(16)		
Depreciation and Amortization	(27)		
Taxes Other Than Income Taxes	(12)		
Carrying Costs Income	(5)		
Interest Expense	(6)		
Total Change in Operating Expenses and Other			(66)
Income Tax Expense			1
Six Months Ended June 30, 2006		$	84

Net Income remained relatively flat for the six months ended June 30, 2006 compared to the six months ended June 30, 2005.

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

- Retail Margins increased $56 million primarily due to the RSP and Transition Regulatory Asset rate increases effective January 1, 2006 as well as the addition of Monongahela Power Ohio customers on December 31, 2005, partially offset by an increase in delivered fuel costs.
- Off-system Sales increased $9 million due to higher physical sales partially offset by lower optimization activity.

- Transmission Revenues decreased $7 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a $3 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the “SECA Revenue Subject to Refund” section of Note 3 - Rate Matters.
- Other revenues increased $9 million primarily due to higher gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance increased $16 million due to the 2005 establishment of a regulatory asset for PJM administrative fees, an increase in transmission expenses related to the AEP Transmission Equalization Agreement and favorable adjustments in the prior year related to the corporate-owned life insurance policy.
- Depreciation and Amortization expense increased $27 million primarily due to the 2005 RSP order that resulted in the reversal of unused shopping credits of $18 million partially offset by the establishment of a $7 million regulatory liability to benefit low-income customers and for economic development. Depreciation expense also increased due to a greater depreciable base resulting primarily from the acquisitions of the Waterford Plant and Monongahela Power’s Ohio assets in the second half of 2005.
- Taxes Other Than Income Taxes increased $12 million due to increases in real and personal property taxes.
- Carrying Costs Income decreased $5 million primarily due to the completion of deferrals of the environmental carrying costs from 2004 and 2005 that are now recovered during 2006 through 2008 according to RSP.
- Interest Expense increased $6 million primarily due to a new long-term debt issuance during the fourth quarter of 2005.

Income Tax

The decrease of $1 million in Income Tax Expense is primarily due to a decrease in 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	A-

Financing Activity

There were no long-term debt issuances or retirements during the first six months of 2006.

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 2005 Annual Report and has not changed significantly from year-end.

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, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the “Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries” section. An adverse result in these proceedings has 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 2005 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. 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 June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of June 30, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 42,197	$ 10,989	$ -	$ 53,186
Noncurrent Assets	74,861	585	-	75,446
Total MTM Derivative Contract Assets	117,058	11,574	-	128,632
Current Liabilities	(31,803)	(2,354)	(952)	(35,109)
Noncurrent Liabilities	(51,549)	-	(6,108)	(57,657)
Total MTM Derivative Contract Liabilities	(83,352)	(2,354)	(7,060)	(92,766)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 33,706	$ 9,220	$ (7,060)	$ 35,866

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 33,322
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(4,894)
Fair Value of New Contracts at Inception When Entered During the Period (a)	139
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(673)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	364
Changes in Fair Value Due to Market Fluctuations During the Period (b)	9,198
Changes Due to SIA (c)	(3,864)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	114
Total MTM Risk Management Contract Net Assets	33,706

Net Cash Flow Hedge Contracts		9,220
DETM Assignment (e)		(7,060)
Total MTM Risk Management Contract Net Assets at June 30, 2006	$	35,866

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 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 giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of June 30, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted - Exchange Traded Contracts	$ (2,051)	$ 2,293	$ 2,348	$ -	$ -	$ -	$ 2,590
Prices Provided by Other External Sources - OTC Broker Quotes (a)	6,669	6,064	2,261	4,422	-	-	19,416
Prices Based on Models and Other Valuation Methods (b)	178	618	1,714	2,434	5,146	1,610	11,700
Total	$ 4,796	$ 8,975	$ 6,323	$ 6,856	$ 5,146	$ 1,610	$ 33,706

(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.

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 employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

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, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2006
(in thousands)

		Power
Beginning Balance in AOCI December 31, 2005	$	(859)
Changes in Fair Value		6,479
Impact due to Changes in SIA (a)		(261)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled		643
Ending Balance in AOCI June 30, 2006	$	6,002

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $5,624 thousand gain.

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 June 30, 2006, 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:

Six Months Ended June 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$405	$948	$411	$237	$424	$705	$335	$121

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 $84 million and $86 million at June 30, 2006 and December 31, 2005, 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 and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2006	**2005**	**2006**	**2005**
REVENUES				
Electric Generation, Transmission and Distribution	$ 395,347	$ 337,563	$ 810,346	$ 669,882
Sales to AEP Affiliates	21,762	22,427	35,531	57,241
TOTAL	417,109	359,990	845,877	727,123
EXPENSES				
Fuel and Other Consumables for Electric Generation	71,213	52,203	141,033	118,638
Purchased Electricity for Resale	27,688	8,703	52,453	17,906
Purchased Electricity from AEP Affiliates	87,188	95,172	169,665	174,947
Other Operation	57,866	53,328	113,827	96,557
Maintenance	23,502	26,700	41,436	42,084
Depreciation and Amortization	46,534	27,333	92,346	65,531
Taxes Other Than Income Taxes	41,787	32,993	81,289	69,235
TOTAL	355,778	296,432	692,049	584,898
OPERATING INCOME	61,331	63,558	153,828	142,225
Other Income (Expense):				
Interest Income	475	711	930	1,628
Carrying Costs Income	1,320	4,159	2,036	6,916
Allowance for Equity Funds Used During Construction	343	528	807	807
Interest Expense	(16,914)	(15,669)	(34,434)	(28,581)
INCOME BEFORE INCOME TAXES	46,555	53,287	123,167	122,995
Income Tax Expense	14,293	18,636	39,568	40,876
NET INCOME	32,262	34,651	83,599	82,119
Capital Stock Expense	40	1,858	79	2,112
EARNINGS APPLICABLE TO COMMON STOCK	$ 32,222	$ 32,793	$ 83,520	$ 80,007

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 Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 41,026	$ 577,415	$ 341,025	$ (60,816)	$ 898,650
Common Stock Dividends			(57,000)		(57,000)
Capital Stock Expense		2,112	(2,112)		-
TOTAL					841,650
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,307				(4,285)	(4,285)
NET INCOME			82,119		82,119
TOTAL COMPREHENSIVE INCOME					77,834
JUNE 30, 2005	$ 41,026	$ 579,527	$ 364,032	$ (65,101)	$ 919,484
DECEMBER 31, 2005	$ 41,026	$ 580,035	$ 361,365	$ (880)	$ 981,546
Common Stock Dividends			(45,000)		(45,000)
Capital Stock Expense		79	(79)		-
TOTAL					936,546
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,695				6,861	6,861
NET INCOME			83,599		83,599
TOTAL COMPREHENSIVE INCOME					90,460
JUNE 30, 2006	$ 41,026	$ 580,114	$ 399,885	$ 5,981	$ 1,027,006

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 810	$ 940
Advances to Affiliates	12,616	-
Accounts Receivable:		
Customers	52,106	43,143
Affiliated Companies	30,840	67,694
Accrued Unbilled Revenues	8,361	10,086
Miscellaneous	2,592	2,012
Allowance for Uncollectible Accounts	(1,320)	(1,082)
Total Accounts Receivable	92,579	121,853
Fuel	40,277	28,579
Materials and Supplies	30,485	27,519
Emission Allowances	11,283	20,181
Risk Management Assets	53,186	76,507
Accrued Tax Benefits	4,360	36,838
Margin Deposits	584	16,832
Prepayments and Other	8,529	6,714
TOTAL	254,709	335,963
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,883,890	1,874,652
Transmission	470,586	457,937
Distribution	1,441,468	1,380,722
Other	186,456	184,096
Construction Work in Progress	179,675	129,246
Total	4,162,075	4,026,653
Accumulated Depreciation and Amortization	1,564,597	1,500,858
TOTAL - NET	2,597,478	2,525,795
OTHER NONCURRENT ASSETS		
Regulatory Assets	223,554	231,599
Long-term Risk Management Assets	75,446	101,512
Deferred Charges and Other	208,185	237,925
TOTAL	507,185	571,036
TOTAL ASSETS	$ 3,359,372	$ 3,432,794

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
June 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 17,609
Accounts Payable:		
General	85,945	59,134
Affiliated Companies	50,801	59,399
Risk Management Liabilities	35,109	69,036
Customer Deposits	32,170	47,013
Accrued Taxes	103,342	157,729
Accrued Interest	19,395	18,908
Other	29,772	31,321
TOTAL	356,534	460,149
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	1,097,121	1,096,920
Long-term Debt - Affiliated	100,000	100,000
Long-term Risk Management Liabilities	57,657	84,291
Deferred Income Taxes	501,286	498,232
Regulatory Liabilities and Deferred Investment Tax Credits	173,058	165,344
Deferred Credits and Other	46,710	46,312
TOTAL	1,975,832	1,991,099
TOTAL LIABILITIES	2,332,366	2,451,248
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - No Par Value Per Share:		
Authorized - 24,000,000 Shares		
Outstanding - 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,114	580,035
Retained Earnings	399,885	361,365
Accumulated Other Comprehensive Income (Loss)	5,981	(880)
TOTAL	1,027,006	981,546
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,359,372	$ 3,432,794

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 83,599	$ 82,119
Adjustments for Noncash Items:		
Depreciation and Amortization	92,346	65,531
Deferred Income Taxes	(250)	(1,593)
Mark-to-Market of Risk Management Contracts	(466)	(5,171)
Deferred Property Taxes	30,201	32,210
Change in Other Noncurrent Assets	(17,206)	(55,746)
Change in Other Noncurrent Liabilities	7,111	4,287
Changes in Components of Working Capital:		
Accounts Receivable, Net	29,274	21,688
Fuel, Materials and Supplies	(14,664)	(2,493)
Accounts Payable	16,866	(1,220)
Accrued Taxes, Net	(21,909)	(93,089)
Customer Deposits	(14,843)	7,618
Other Current Assets	24,796	334
Other Current Liabilities	(1,062)	948
Net Cash Flows From Operating Activities	213,793	55,423
INVESTING ACTIVITIES		
Construction Expenditures	(137,728)	(79,013)
Change in Advances to Affiliates, Net	(12,616)	79,378
Other	600	3,663
Net Cash Flows From (Used For) Investing Activities	(149,744)	4,028
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(17,609)	-
Principal Payments for Capital Lease Obligations	(1,570)	(1,815)
Dividends Paid on Common Stock	(45,000)	(57,000)
Net Cash Flows Used For Financing Activities	(64,179)	(58,815)
Net Increase (Decrease) in Cash and Cash Equivalents	(130)	636
Cash and Cash Equivalents at Beginning of Period	940	58
Cash and Cash Equivalents at End of Period	$ 810	$ 694
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 32,374	$ 27,390
Cash Paid for Income Taxes, Net of Refunds	10,713	78,019
Noncash Acquisitions Under Capital Leases	1,648	343
Construction Expenditures Included in Accounts Payable at June 30,	12,601	4,426

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 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 FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)

Second Quarter of 2005		$ 36
Changes in Gross Margin:		
Retail Margins	(18)	
Off-system Sales (a)	16	
Transmission Revenues	(9)	
Other	(4)	
Total Change in Gross Margin		(15)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	8	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	(3)	
Interest Expense	(1)	
Total Change in Operating Expenses and Other		2
Income Tax Expense		6
Second Quarter of 2006		$ 29

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

Net Income decreased $7 million to $29 million in 2006. The key driver of the decrease was a $15 million decrease in Gross Margin, partially offset by a $6 million decrease in Income Tax Expense.

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 $18 million primarily due to lower fuel recovery as fuel cost increases could not be recovered due to the Indiana fuel cap and a reduction in capacity settlement revenues of $8 million under the Interconnection Agreement.
- Off-system Sales increased $16 million primarily due to the addition of new municipal contracts including new rates and increased demand beginning January 2006.
- Transmission Revenues decreased $9 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a $3 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $8 million primarily due to a reduction in maintenance expenses for coal and nuclear generation facilities.

Income Taxes

Income Tax Expense decreased $6 million primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income
(in millions)

Six Months Ended June 30, 2005		$ 75
Changes in Gross Margin:		
Retail Margins	(11)	
Off-system Sales (a)	29	
Transmission Revenues		