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

Results of Operations

Third Quarter of 2005 Compared to Third Quarter of 2004

Reconciliation of Third Quarter of 2004 to Third Quarter of 2005 Net Income (in millions)

Third Quarter of 2004 Net Income		$ 17
Changes in Gross Margin:		
Texas Supply	(5)	
Texas Wires	2	
Off-system Sales	2	
Transmission Revenues	(1)	
Other Revenues	5	
Total Change in Gross Margin		3
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	5	
Depreciation and Amortization	(1)	
Total Change in Operating Expenses and Other		4
Income Tax Expense		(2)
Third Quarter of 2005 Net Income		$ 22

Net income increased $5 million due mainly to increases in gross margin and reduced operating expenses.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Texas Supply margins decreased by $5 million primarily due to lower sales volumes of 55% due to the expiration of the supply contract with our largest REP customer offset by an increase in nonaffiliated margin and capacity sales.
- Texas Wires revenue increased by $2 million primarily due to an increase in sales volumes of 10% resulting from a 29% increase in cooling degree days .
- Margins from Off-system Sales increased by $2 million primarily due to favorable optimization activity.
- Other Revenue increased $5 million primarily due to an increase in ancillary services to ERCOT.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $5 million. The decrease was primarily due to lower expenses for power plants no longer in service and a favorable settlement related to the Ft. Davis wind farm, which was impaired in 2002. A further reduction includes administrative and general expenses, primarily related to lower employee-related costs.

Income Taxes

The effective tax rates for the third quarter of 2005 and 2004 were 32.5% and 33.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, federal income tax adjustments and state income taxes. The effective tax rate remained relatively flat for the comparative period.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Reconciliation of Nine Months Ended September 30, 2004 to Nine Months Ended September 30, 2005 Net Income (in millions)

Nine Months Ended September 30, 2004 Net Income		$ 38
Changes in Gross Margin:		
Texas Supply	(5)	
Texas Wires	4	
Off-system Sales	(1)	
Other Revenues	1	
Total Change in Gross Margin		(1)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	7	
Depreciation and Amortization	(2)	
Nonoperating Income and Expenses, Net	(2)	
Interest Charges	2	
Total Change in Operating Expenses and Other		5
Income Tax Expense		-
Nine Months Ended September 30, 2005 Net Income		$ 42

Net income increased $4 million due mainly to reduced operating expenses.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Texas Supply margins decreased by $5 million primarily due to a decrease of $29 million due to lower sales volumes of 35% resulting from the expiration of the supply contract with our largest REP customer, offset by a decrease in the provision for refunds of $13 million for the 2004 final fuel reconciliation true-up and increased capacity revenue of $10 million.

- Texas Wires revenue increased by $4 million primarily due to higher sales volumes of 7% resulting from a 9% increase in degree days.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $7 million primarily due to decreased operations and maintenance for plants no longer in service. Production expense was further reduced by a favorable settlement related to the Ft. Davis wind farm, which was impaired in 2002, offset in part by increased cost for the disposal of fuel oil inventory. Further decreases were related to reduced customer expense and administrative and general expenses including employee-related costs.
- Nonoperating Income and Expenses, Net decreased $2 million primarily due to $5 million of income in 2004 relating to optimization contracts which expired in December 2004 offset by increased margins of $2 million from third party construction projects and increased interest income of $1 million.
- Interest Charges decreased $2 million primarily due to long-term debt maturities in 2004 and interest in 2004 related to the FERC settlement with wholesale customers.

Income Taxes

The effective tax rates for the nine months ended September 30, 2005 and 2004 were 30.7% and 33.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to state income taxes and changes in permanent differences.

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	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Financing Activity

There were no long-term debt issuances or retirements during the first nine months of 2005.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 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.

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' effects on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	4,192
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(1,705)
Fair Value of New Contracts When Entered During the Period (b)		32
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		2,125
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		4,644
Net Cash Flow Hedge Contracts (f)		(1,502)
Total MTM Risk Management Contract Net Assets at September 30, 2005	$	3,142

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. 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.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2005.

(d) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(e) "Changes in Fair Value of Risk Management Contracts 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 assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to Condensed Balance Sheets As of September 30, 2005 (in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 13,918	$ 39	$ 13,957
Noncurrent Assets	8,324	43	8,367
Total MTM Derivative Contract Assets	22,242	82	22,324
Current Liabilities	(12,201)	(1,538)	(13,739)
Noncurrent Liabilities	(5,397)	(46)	(5,443)
Total MTM Derivative Contract Liabilities	(17,598)	(1,584)	(19,182)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,644	$ (1,502)	$ 3,142

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Condensed Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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 September 30, 2005

(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (268)	$ 1,288	$ 108	$ 59	$ -	$ -	$ 1,187
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,004	702	1,595	595	-	-	4,896
Prices Based on Models and Other Valuation Methods (b)	(265)	(1,509)	(1,083)	168	596	654	(1,439)
Total	$ 1,471	$ 481	$ 620	$ 822	$ 596	$ 654	$ 4,644

(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 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.

(c) Amounts exclude Cash Flow Hedges.

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

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may 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.

The table provides detail on designated, effective cash flow hedges included in the Condensed Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 285
Changes in Fair Value (a)	(1,232)

Reclassifications from AOCI to Net Income (b)	(64)
Ending Balance September 30, 2005	$ (1,011)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at September 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,010 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$94	$129	$61	$32	$68	$221	$95	$33

VaR Associated with Debt Outstanding

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 $14 million and $13 million at September 30, 2005 and December 31, 2004, 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 operation or financial position.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Nine Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 111,229	$ 139,904	$ 280,502	$ 318,946
Sales to AEP Affiliates	13,019	12,599	37,189	39,344
TOTAL	124,248	152,503	317,691	358,290
OPERATING EXPENSES				
Fuel for Electric Generation	13,289	11,357	37,255	29,518
Fuel from Affiliates for Electric Generation	144	15,497	516	39,263
Purchased Electricity for Resale	34,425	51,517	88,367	92,822
Purchased Electricity from AEP Affiliates	1	309	23	4,385
Other Operation	17,054	23,212	58,019	64,511
Maintenance	5,954	4,544	15,093	15,177
Depreciation and Amortization	10,435	9,448	30,952	28,994
Taxes Other Than Income Taxes	6,047	6,476	17,465	16,873
Income Taxes	10,504	8,248	17,183	16,730
TOTAL	97,853	130,608	264,873	308,273
OPERATING INCOME	26,395	21,895	52,818	50,017
Nonoperating Income	2,878	8,637	44,093	38,025
Nonoperating Expenses	1,826	8,230	39,139	31,128
Nonoperating Income Tax Expense	212	83	1,286	2,186
Interest Charges	4,931	5,366	14,784	17,028
NET INCOME	22,304	16,853	41,702	37,700
Preferred Stock Dividend Requirements	26	26	78	78
EARNINGS APPLICABLE TO COMMON STOCK	$ 22,278	$ 16,827	$ 41,624	$ 37,622

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 137,214	$ 2,351	$ 125,428	$ (26,718)	$238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(78)		(78)
TOTAL					236,197
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $980				(1,820)	(1,820)
NET INCOME			37,700		37,700
TOTAL COMPREHENSIVE INCOME					35,880
SEPTEMBER 30, 2004	$ 137,214	$ 2,351	$ 161,050	$ (28,538)	$272,077
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$310,421
Common Stock Dividends			(20,827)		(20,827)
Preferred Stock Dividends			(78)		(78)
TOTAL					289,516
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $698				(1,296)	(1,296)
NET INCOME			41,702		41,702
TOTAL COMPREHENSIVE INCOME					40,406
SEPTEMBER 30, 2005	$ 137,214	$ 2,351	$ 191,781	$ (1,424)	$329,922

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 288,446	$ 287,212
Transmission	288,538	281,359
Distribution	489,002	474,961
General	110,831	115,174
Construction Work in Progress	34,808	23,621
Total	1,211,625	1,182,327
Accumulated Depreciation and Amortization	417,521	405,933
TOTAL - NET	794,104	776,394
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	1,177	1,407
CURRENT ASSETS		
Cash and Cash Equivalents	215	-
Other Cash Deposits	800	2,308
Advances to Affiliates	87,651	51,504
Accounts Receivable:		
Customers	59,400	90,109
Affiliated Companies	31,564	21,474
Accrued Unbilled Revenues	5,880	3,789
Allowance for Uncollectible Accounts	(9)	(787)
Unbilled Construction Costs	3,119	22,065
Fuel Inventory	1,918	3,148
Materials and Supplies	8,581	8,273
Risk Management Assets	13,957	6,071
Margin Deposits	4,952	818
Prepayments and Other	5,159	1,053
TOTAL	223,187	209,825
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Deferred Debt - Restructuring	5,727	6,093
Unamortized Loss on Reacquired Debt	1,122	2,147

Other	3,292	3,783
Long-term Risk Management Assets	8,367	4,110
Prepaid Pension Obligations	44,901	44,911
Deferred Property Taxes	4,072	-
Other Deferred Charges	2,232	2,859
TOTAL	69,713	63,903
TOTAL ASSETS	$ 1,088,181	$ 1,051,529

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
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	191,781	170,984
Accumulated Other Comprehensive Income (Loss)	(1,424)	(128)
Total Common Shareholder's Equity	329,922	310,421
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholders' Equity	332,279	312,778
Long-term Debt - Nonaffiliated	276,822	276,748
TOTAL	609,101	589,526
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	37,609	37,609
Accounts Payable:		
General	35,404	22,444
Affiliated Companies	49,563	52,801
Customer Deposits	6,491	1,020
Taxes Accrued	27,172	37,269
Interest Accrued	3,378	5,044
Risk Management Liabilities	13,739	3,628
Obligations Under Capital Leases	196	220
Other	10,767	9,628
TOTAL	184,319	169,663
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	141,451	138,465
Long-term Risk Management Liabilities	5,443	2,116
Regulatory Liabilities:		
Asset Removal Costs	81,756	81,143
Deferred Investment Tax Credits	17,745	18,698
Over-recovery of Fuel Costs	4,815	3,920
Retail Clawback	13,924	13,924
Excess Earnings	12,898	13,270

SFAS 109 Regulatory Liability, Net	6,897	8,500
Other	921	1,319
Obligations Under Capital Leases	348	314
Deferred Credits and Other	8,563	10,671
TOTAL	294,761	292,340
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,088,181	$ 1,051,529

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 41,702	$ 37,700
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	30,952	28,994
Deferred Income Taxes	(313)	(1,980)
Deferred Investment Tax Credits	(953)	(974)
Pension and Postemployment Benefit Reserves	(513)	-
Deferred Property Taxes	(4,072)	(4,023)
Mark-to-Market of Risk Management Contracts	(452)	1,318
Over/Under Fuel Recovery	895	13,500
Change in Other Noncurrent Assets	(672)	(9,800)
Change in Other Noncurrent Liabilities	349	(266)
Changes in Components of Working Capital:		
Accounts Receivable, Net	17,750	(7,345)
Fuel, Materials and Supplies	922	4,447
Accounts Payable	8,467	(3,267)
Taxes Accrued	(10,097)	16,879
Customer Deposits	5,471	1,342
Interest Accrued	(1,666)	(1,962)
Other Current Assets	10,706	(6,171)
Other Current Liabilities	1,115	(2,264)
Net Cash Flows From Operating Activities	99,591	66,128
INVESTING ACTIVITIES		
Construction Expenditures	(44,865)	(27,742)
Change in Other Cash Deposits, Net	1,508	266
Proceeds from Sale of Assets	1,033	510
Net Cash Flows Used For Investing Activities	(42,324)	(26,966)
FINANCING ACTIVITIES		
Retirement of Long-term Debt	-	(24,036)
Changes in Advances to/from Affiliates, Net	(36,147)	(12,902)
Dividends Paid on Common Stock	(20,827)	(2,000)
Dividends Paid on Cumulative Preferred Stock	(78)	(78)

Net Cash Flows Used For Financing Activities	(57,052)	(39,016)
Net Increase in Cash and Cash Equivalents	215	146
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ 215	$ 146

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $15,192,000 and $17,290,000 and for income taxes was $30,486,000 and $6,905,000 in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 and 2004 were $193,000 and $153,000, respectively. Construction Expenditures include the change in Construction-related Accounts Payable of $1,255,000 and $(726,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

The condensed notes to TNC's condensed financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to TNC.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Customer Choice and Industry Restructuring	Note 4
Commitments and Contingencies	Note 5
Guarantees	Note 6
Benefit Plans	Note 8
Business Segments	Note 9
Income Taxes	Note 10
Financing Activities	Note 11
Company-wide Staffing and Budget Review	Note 12

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Third Quarter of 2005 Compared to Third Quarter of 2004

Reconciliation of Third Quarter of 2004 to Third Quarter of 2005 Net Income
(in millions)

Third Quarter of 2004 Net Income		$ 38
Changes in Gross Margin:		
Retail Margins	10	
Off-system Sales	12	
Transmission Revenues	(6)	
Other Revenues	4	
Total Change in Gross Margin		20
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(19)	
Depreciation and Amortization	(1)	
Nonoperating Income and Expenses, Net	4	
Total Change in Operating Expenses and Other		(16)
Income Tax Expense		(5)
Third Quarter of 2005 Net Income		$ 37

Net Income decreased by $1 million to $37 million in the third quarter of 2005 in comparison to the third quarter of 2004. The key drivers of the decrease were a $16 million net increase in operating expenses and other and a $5 million increase in Income Tax Expense offset by a $20 million increase in gross margin.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins increased by $10 million in comparison to 2004 primarily due to increases in retail sales. Cooling degree days were 35% higher than 2004.
- Off-system sales margins for 2005 increased by $12 million compared to 2004 primarily due to increased AEP Power Pool physical sales as well as favorable optimization activity.
- Transmission Revenues decreased $6 million primarily due to the elimination of $11 million of revenues related to through and out rates partially offset by an increase of $5 million in revenues due to replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.

Operating expenses and other changed between years as follows:

- Other Operation and Maintenance expenses increased $19 million primarily due to $6 million of distribution right-of-way activities and maintenance, a $4 million true-up related to the Virginia Environmental and Reliability deferral and a $3 million increase in system dispatch costs related to our operation in PJM.
- Nonoperating Income and Expenses, Net increased $4 million primarily due to favorable optimization activity coupled with the accrual of carrying costs related to the Virginia Environmental and Reliability deferral.

Income Taxes

The effective tax rates for the third quarter of 2005 and 2004 were 35.8% and 29.6%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to federal income tax adjustments.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Reconciliation of Nine Months Ended September 30, 2004 to Nine Months Ended September 30, 2005 Net Income (in millions)

Nine Months Ended September 30, 2004 Net Income		$ 126
Changes in Gross Margin:		
Retail Margins	(56)	
Off-system Sales	44	
Transmission Revenues	(19)	
Other Revenues	7	
Total Change in Gross Margin		(24)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(17)	
Depreciation and Amortization	(3)	
Taxes Other Than Income Taxes	(1)	
Nonoperating Income and Expenses, Net	7	
Total Change in Operating Expenses and Other		(14)
Income Tax Expense		20
Nine Months Ended September 30, 2005 Net Income		$ 108

Net Income decreased by $18 million to $108 million in the nine months ended September 30, 2005 in comparison to the nine months ended September 30, 2004. The key drivers of the decrease were a $24 million decrease in gross margin and a $14 million net increase in operating expenses and other partially offset by a $20 million decrease in Income Tax Expense.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased by $56 million in comparison to 2004 primarily due to our higher MLR share caused by the increase in our peak demand established in December 2004 resulting in a $45 million increase in capacity settlement payments under the Interconnection Agreement. In addition, there was a $20 million decrease in fuel margins resulting from higher fuel costs.
- Off-system sales margins for 2005 increased by $44 million compared to 2004 primarily due to increased AEP Power Pool physical sales as well as favorable optimization activity.
- Transmission Revenues decreased $19 million primarily due to the elimination of $34 million of revenues related to through and out rates partially offset by an increase of $15 million due to replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $17 million primarily due to a $10 million increase in system dispatch costs related to our operation in PJM and an increase in transmission equalization charges due to the increase in our MLR as a result of our new peak demand established in December 2004.
- Nonoperating Income and Expenses, Net increased $7 million primarily due to the accrual of carrying costs related to the Virginia Environmental and Reliability deferral coupled with favorable optimization activity.

Income Taxes

The effective tax rates for the nine months ended September 2005 and 2004 were 33.5% and 37.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to an investment tax credit adjustment in 2004 as a result of the Virginia SCC extending the regulatory transition period and a decrease in 2005 state income taxes as a result of recording the effects of Ohio House Bill 66, which phases-out the Ohio Franchise Tax. Participation in the SIA subjects us to the Ohio Franchise Tax.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch

First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

Cash Flow

Cash flows for the nine months ended September 30, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 536	$ 4,561
Cash Flows From (Used For):		
Operating Activities	175,640	393,181
Investing Activities	(410,881)	(256,295)
Financing Activities	236,270	(137,949)
Net Increase (Decrease) in Cash and Cash Equivalents	1,029	(1,063)
Cash and Cash Equivalents at End of Period	$ 1,565	$ 3,498

Operating Activities

Our Net Cash Flows From Operating Activities were $176 million in 2005. We produced income of $108 million during the period and noncash expense items of $147 million for Depreciation and Amortization partially offset by Pension Contributions of $60 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.

Our Net Cash Flows From Operating Activities were $393 million in 2004. We produced income of $126 million during the period and had a noncash expense item of $144 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items.

Investing Activities

Our Net Cash Flows Used For Investing Activities during 2005 and 2004 primarily reflect our Construction Expenditures of $422 million and $300 million, respectively. Construction Expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In 2005 and 2004, capital projects for transmission expenditures are primarily related to the Jacksons Ferry-Wyoming 765 kV transmission line. Environmental upgrades include the installation of SCR equipment on Amos Unit 1 and the flue gas desulfurization project at the Mountaineer Plant. For the remainder of 2005, we expect our Construction Expenditures to be approximately $270 million.

Financing Activities

Our Net Cash Flows From Financing Activities were $236 million in 2005. We issued four Senior Unsecured Notes totaling $850 million with various interest rates. We also issued Notes Payable - Affiliates of $100 million and received a capital contribution from our parent of $150 million. We retired $450 million of Senior Unsecured Notes with an interest rate of 4.80% and retired three First Mortgage Bonds totaling $125 million with various interest rates. In addition, we repaid $279 million of Advances from Affiliates.

Our Net Cash Flows Used For Financing Activities were $138 million in 2004. We retired $45 million and $21 million of First Mortgage Bonds and $40 million of Installment Purchase Contracts with interest rates of 7.13%, 7.70 and 5.45%, respectively. In addition, we repaid $107 million of Advances from Affiliates and paid $50 million in Common Stock Dividends.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 250,000	5.00	2017
Senior Unsecured Notes	250,000	5.80	2035
Senior Unsecured Notes	200,000	4.95	2015
Senior Unsecured Notes	150,000	4.40	2010
Notes Payable - Affiliated	100,000	4.708	2010

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 450,000	4.80	2005
First Mortgage Bonds	50,000	8.00	2005
First Mortgage Bonds	45,000	8.00	2025
First Mortgage Bonds	30,000	6.89	2005

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end other than the issuances and retirements discussed above and the coal supply agreement discussed below.

We entered into a 11-year coal supply agreement effective January 1, 2007, with Cline Resources & Development Company (Gatling LLC). The agreement requires a minimum purchase of two million tons of coal per year. The contract contains routine remedy clauses in case of default.

Significant Factors

Ceredo Generating Station

In August 2005, we signed a purchase and sale agreement with Reliant Energy for the purchase of a 505 MW plant located near Ceredo, West Virginia for $100 million. This transaction is expected to be completed no later than the first quarter of 2006.

Virginia Environmental and Reliability Costs

In April 2004, the Virginia Electric Restructuring Act was amended to include a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and T&D system reliability (E&R) costs prudently incurred after July 1, 2004. On July 1, 2005, we filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. The $62 million request represents i) expected costs of environmental controls on coal-fired generators to meet the first phase of the Clean Air Interstate Rule and Clean Air Mercury Rule finalized earlier this year, ii) recovery of the incremental cost of the Jacksons Ferry-Wyoming 765 kV transmission line construction and iii) other incremental T&D system reliability costs incurred from July 1, 2004 to June 30, 2006.

In our filing, we requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. The recovery factor would have been applied as a 9.18% surcharge to customer bills. We proposed to practice over/under-recovery deferral accounting for the difference between the actual incremental costs incurred and revenue recovered.

Through September 30, 2005, we have incurred approximately $13 million of actual incremental E&R costs and have deferred $7 million of such costs for future recovery. APCo did not record $2 million of equity carrying costs that are not recognized until collected. E&R costs of $4 million represented interest capitalized that was duplicative of the carrying costs.

On October 14, 2005, the Virginia SCC denied our request to place in effect, on an interim basis subject to refund, its proposed cost recovery surcharge. Under this order, an E&R surcharge will not become effective until the Virginia SCC issues an order following the February 7, 2006 public hearing in this case. The Virginia SCC also ruled in this order that it does not have the authority under applicable Virginia law to approve the recovery of projected E&R costs before their actual incurrence and adjudication, which effectively eliminated projected costs requested in this filing. However, according to this order, we may update our request to reflect additional actual costs and/or present additional evidence. If the Virginia SCC denies recovery of any portion of the net incremental amounts deferred to date, it would adversely affect future results of operations and cash flows.

West Virginia Rate Case

On August 26, 2005, we, in a joint filing with WPCo, filed an application with the Public Service Commission of West Virginia seeking an initial increase in our retail rates of approximately $77 million. The initial increase included approval to reactivate and modify the suspended Expanded Net Energy Cost (ENEC) Recovery Mechanism which accounted for $65 million of the initial increase and approval to implement a system reliability tracker which accounted for $9 million. ENEC includes fuel and purchased power costs, as well as other energy-related items including off-system sales margins and transmission items. In addition, we requested a series of supplemental annual increases related to the recovery of the cost of significant environmental and transmission expenditures. The first proposed supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining supplemental increases of $44 million, $10 million and $38 million would go in effect on January 1, 2007, 2008 and 2009, respectively. It is expected that the proposed rates will become effective on June 23, 2006 under West Virginia law. We have a regulatory liability of $52 million pre-suspension, previously over-recovered ENEC costs which we are proposing to apply plus a carrying cost in the future to any of under-recoveries of ENEC costs through the reactivated ENEC Recovery Mechanism. Management is unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 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.

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

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	54,124
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(10,775)
Fair Value of New Contracts When Entered During the Period (b)		682
Net Option Premiums Paid/(Received) (c)		(685)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		18,118
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		5,741
Total MTM Risk Management Contract Net Assets		67,205
Net Cash Flow and Fair Value Hedge Contracts (f)		(14,929)
DETM Assignment (g)		(15,405)
Total MTM Risk Management Contract Net Assets at September 30, 2005	$	36,871

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. 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.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2005.

(d) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(e) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.
(f) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheets As of September 30, 2005 (in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 194,468	$ 361	$ -	$ 194,829
Noncurrent Assets	176,644	397	-	177,041
Total MTM Derivative Contract Assets	371,112	758	-	371,870
Current Liabilities	(170,347)	(14,271)	(3,660)	(188,278)
Noncurrent Liabilities	(133,560)	(1,416)	(11,745)	(146,721)
Total MTM Derivative Contract Liabilities	(303,907)	(15,687)	(15,405)	(334,999)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 67,205	$ (14,929)	$ (15,405)	$ 36,871

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Condensed Consolidated Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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 September 30, 2005 (in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (2,461)	$ 11,840	$ 996	$ 545	$ -	$ -	$10,920
Prices Provided by Other External Sources - OTC Broker Quotes (a)	18,934	13,138	18,121	7,227	1,057	-	58,477
Prices Based on Models and Other Valuation Methods (b)	(1,902)	(10,877)	(6,413)	3,788	7,926	5,286	(2,192)
Total	$ 14,571	$ 14,101	$12,704	$11,560	$8,983	$5,286	$67,205

(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 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.

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $7.5 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow and Fair Value Hedges.

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

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may 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 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 table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2005
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance December 31, 2004	$ 2,422	$ (176)	$ (11,570)	$ (9,324)
Changes in Fair Value (a)	(7,947)	-	(4,866)	(12,813)
Reclassifications from AOCI to Net Income (b)	(3,780)	3	1,100	(2,677)
Ending Balance September 30, 2005	$ (9,305)	$ (173)	$ (15,336)	$ (24,814)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at September 30, 2005. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $11,509 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low

$868	$1,183	$558	$297	$577	$1,883	$812	$277

VaR Associated with Debt Outstanding

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 $145 million and $99 million at September 30, 2005 and December 31, 2004, 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 operation or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Nine Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 497,663	$ 428,688	$ 1,441,352	$ 1,316,778
Sales to AEP Affiliates	69,381	58,726	178,298	163,655
TOTAL	567,044	487,414	1,619,650	1,480,433
OPERATING EXPENSES				
Fuel for Electric Generation	155,185	117,841	391,583	327,246
Purchased Electricity for Resale	24,217	19,727	79,182	54,157
Purchased Electricity from AEP Affiliates	108,008	90,257	341,994	268,537
Other Operation	81,156	70,724	229,448	211,524
Maintenance	44,865	36,240	129,321	130,493
Depreciation and Amortization	50,284	48,877	146,734	144,021
Taxes Other Than Income Taxes	23,662	22,995	71,023	69,947
Income Taxes	20,903	18,063	55,901	78,339
TOTAL	508,280	424,724	1,445,186	1,284,264
OPERATING INCOME	58,764	62,690	174,464	196,169
Nonoperating Income	5,554	571	13,744	9,149
Carrying Costs Income	1,255	65	5,320	187
Nonoperating Expenses	3,291	1,497	10,295	7,239
Nonoperating Income Tax Credit	66	1,899	1,344	3,524
Interest Charges	24,976	25,269	76,320	76,169
NET INCOME	37,372	38,459	108,257	125,621
Preferred Stock Dividend Requirements, Including Capital Stock Expense and Other Expense	238	796	1,940	2,417
EARNINGS APPLICABLE TO COMMON STOCK	$ 37,134	$ 37,663	$ 106,317	$ 123,204

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

See Condensed Notes to 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 Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 260,458	$719,899	$ 408,718	$ (52,088)	$1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(600)		(600)
Capital Stock Expense		1,817	(1,817)		-
TOTAL					1,286,387
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,746				(14,366)	(14,366)
NET INCOME			125,621		125,621
TOTAL COMPREHENSIVE INCOME					111,255
SEPTEMBER 30, 2004	$ 260,458	$721,716	$ 481,922	$ (66,454)	$1,397,642
DECEMBER 31, 2004	$ 260,458	$722,314	$ 508,618	$ (81,672)	$1,409,718
Capital Contribution from Parent		150,000			150,000
Preferred Stock Dividends			(600)		(600)
Capital Stock Expense and Other		2,485	(1,340)		1,145
TOTAL					1,560,263
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $8,340				(15,490)	(15,490)
NET INCOME			108,257		108,257
TOTAL COMPREHENSIVE INCOME					92,767

SEPTEMBER 30, 2005	$ 260,458	$874,799	$ 614,935	$ (97,162)	$

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 2,705,316	$ 2,502,273
Transmission	1,265,837	1,255,390
Distribution	2,119,502	2,070,377
General	294,533	302,474
Construction Work in Progress	495,661	399,116
Total	6,880,849	6,529,630
Accumulated Depreciation and Amortization	2,499,612	2,443,218
TOTAL - NET	4,381,237	4,086,412
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	20,591	20,378
Other Investments	12,898	18,775
TOTAL	33,489	39,153
CURRENT ASSETS		
Cash and Cash Equivalents	1,565	536
Other Cash Deposits	150	1,133
Advances to Affiliates	67,532	-
Accounts Receivable:		
Customers	153,437	126,422
Affiliated Companies	131,359	140,950
Accrued Unbilled Revenues	28,824	51,427
Miscellaneous	1,427	1,264
Allowance for Uncollectible Accounts	(3,444)	(5,561)
Risk Management Assets	194,829	81,811
Fuel	55,537	45,756
Materials and Supplies	43,330	45,644
Margin Deposits	46,963	8,329
Prepayments and Other	37,312	12,192
TOTAL	758,821	509,903
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		

SFAS 109 Regulatory Asset, Net	329,729	343,415
Transition Regulatory Assets	22,284	25,467
Unamortized Loss on Reacquired Debt	18,174	18,157
Other	83,747	36,368
Long-term Risk Management Assets	177,041	81,245
Emission Allowances	49,257	38,931
Deferred Property Taxes	22,489	37,071
Deferred Charges and Other	8,986	23,796
TOTAL	711,707	604,450
TOTAL ASSETS	$ 5,885,254	$ 5,239,918

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
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	874,799	722,314
Retained Earnings	614,935	508,618
Accumulated Other Comprehensive Income (Loss)	(97,162)	(81,672)
Total Common Shareholder's Equity	1,653,030	1,409,718
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholders' Equity	1,670,814	1,427,502
Long-term Debt:		
Nonaffiliated	1,951,260	1,254,588
Affiliated	100,000	-
Total Long-term Debt	2,051,260	1,254,588
TOTAL	3,722,074	2,682,090
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	100,011	530,010
Advances from Affiliates	-	211,060
Accounts Payable:		
General	197,577	130,710
Affiliated Companies	84,583	76,314
Risk Management Liabilities	188,278	89,136
Taxes Accrued	51,382	90,404
Interest Accrued	36,543	21,076
Customer Deposits	95,124	42,822
Obligations Under Capital Leases	5,760	6,742
Other	52,353	56,645
TOTAL	811,611	1,254,919
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	855,612	852,536
Regulatory Liabilities:		
Asset Removal Costs	92,641	95,763

Over-recovery of Fuel Cost	52,041	57,843
Deferred Investment Tax Credits	26,981	30,382
Unrealized Gain on Forward Commitments	46,246	23,270
Employee Benefits and Pension Obligations	75,340	130,530
Long-term Risk Management Liabilities	146,721	57,349
Asset Retirement Obligations	26,059	24,626
Obligations Under Capital Leases	9,952	13,136
Deferred Credits	19,976	17,474
TOTAL	1,351,569	1,302,909
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,885,254	$ 5,239,918

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 108,257	$ 125,621
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	146,734	144,021
Accretion Expense	1,434	1,298
Deferred Income Taxes	25,103	31,596
Deferred Investment Tax Credits	(3,401)	1,001
Deferred Property Taxes	14,582	14,574
Pension Contributions	(59,812)	(1,047)
Pension and Postemployment Benefit Reserves	4,622	(3,869)
Mark-to-Market of Risk Management Contracts	(21,412)	18,137
Over/Under Fuel Recovery	(21,001)	(3,668)
Carrying Costs Income	(5,320)	(187)
Change in Other Noncurrent Assets	(9,584)	(19,804)
Change in Other Noncurrent Liabilities	(17,825)	8,608
Changes in Components of Working Capital:		
Accounts Receivable, Net	2,899	59,734
Fuel, Materials and Supplies	(7,467)	(7,810)
Accounts Payable	58,112	(30,112)
Taxes Accrued	(39,022)	30,357
Customer Deposits	52,302	11,937
Interest Accrued	15,467	16,707
Other Current Assets	(63,754)	4,629
Other Current Liabilities	(5,274)	(8,542)
Net Cash Flows From Operating Activities	175,640	393,181
INVESTING ACTIVITIES		
Construction Expenditures	(421,544)	(300,068)
Change in Other Cash Deposits, Net	983	40,613
Proceeds from Sale of Assets	9,680	3,160
Net Cash Flows Used For Investing Activities	(410,881)	(256,295)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	840,469	125,430
Issuance of Long-term Debt - Affiliated	100,000	-

Retirement of Long-term Debt	(575,007)	(106,006)
Capital Contribution from Parent	150,000	-
Changes in Advances to/from Affiliates, Net	(278,592)	(106,773)
Dividends Paid on Cumulative Preferred Stock	(600)	(600)
Dividends Paid on Common Stock	-	(50,000)
Net Cash Flows From (Used For) Financing Activities	236,270	(137,949)
Net Increase (Decrease) in Cash and Cash Equivalents	1,029	(1,063)
Cash and Cash Equivalents at Beginning of Period	536	4,561
Cash and Cash Equivalents at End of Period	$ 1,565	$ 3,498

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $56,253,000 and $53,622,000 and for income taxes was $61,514,000 and $(831,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 and 2004 were $1,087,000 and $2,848,000, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $17,024,000 and $370,000 in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

The condensed notes to APCo's condensed consolidated financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to APCo.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments and Contingencies	Note 5
Guarantees	Note 6
Acquisitions, Dispositions, Asset Impairments and Assets Held for Sale	Note 7
Benefit Plans	Note 8
Business Segments	Note 9
Income Taxes	Note 10
Financing Activities	Note 11
Company-wide Staffing and Budget Review	Note 12

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Third Quarter of 2005 Compared to Third Quarter of 2004

Reconciliation of Third Quarter of 2004 to Third Quarter of 2005 Net Income
(in millions)

Third Quarter of 2004 Net Income		$ 53
Changes in Gross Margin:		
Retail Margins	17	
Off-system Sales	15	
Transmission Revenues	(4)	
Other Revenues	2	
Total Change in Gross Margin		30
Changes in Operating Expenses and Other:		
Asset Impairments and Related Charges	(39)	
Other Operation and Maintenance	(10)	
Taxes Other Than Income Taxes	(9)	
Nonoperating Income and Expenses, Net	5	
Interest Charges	1	
Total Change in Operating Expenses and Other		(52)
Income Tax Expense		3
Third Quarter of 2005 Net Income		$ 34

Net Income decreased $19 million to $34 million in 2005. The key drivers of the decrease were a $39 million increase in Asset Impairments and Related Charges, a $10 million increase in Other Operation and Maintenance and a $9 million increase in Taxes Other Than Income Taxes partially offset by a $30 million increase in gross margin.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins were $17 million higher than the prior period primarily due to an increase of 53% in cooling degree days partially offset by lower fuel margins.
- Off-system Sales margins increased $15 million primarily due to increased AEP Power Pool physical sales and favorable optimization activity.
- Transmission Revenues decreased $4 million primarily due to the loss of through and out rates, net

of replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.

Operating Expenses and Other changed between years as follows:

- Asset Impairments and Related Charges increased $39 million due to the commitment to a plan to retire units 1 and 2 at our Conesville Plant. In September, we formally requested permission from PJM to retire the two units effective December 29, 2005. We received preliminary approval on October 21, 2005.
- Other Operation and Maintenance expenses increased $10 million due to increased consumption of NO_x allowances, increased boiler maintenance expenses due to overhaul work from scheduled and forced outages, increased overhead distribution line expenses and increased pension costs.
- Taxes Other Than Income Taxes increased $9 million due to an increase in property tax accruals as a result of increased property values. The increase is also a result of increased state excise taxes due to higher KWH sales.
- Nonoperating Income and Expenses, Net increased $5 million due to favorable optimization activities and the establishment of a regulatory asset for carrying costs on environmental capital expenditures as a result of the rate stabilization plan order.

Income Tax

The effective tax rates for the third quarter of 2005 and 2004 were 38.0% and 31.5%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to state income taxes.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Reconciliation of Nine Months Ended September 30, 2004 to Nine Months Ended September 30, 2005 Net Income (in millions)

Nine Months Ended September 30, 2004 Net Income		$ 128
Changes in Gross Margin:		
Retail Margins	7	
Off-system Sales	21	
Transmission Revenues	(15)	
Other Revenues	1	
Total Change in Gross Margin		14
Changes in Operating Expenses and Other:		
Asset Impairments and Related Charges	(39)	
Other Operation and Maintenance	1	
Depreciation and Amortization	8	
Taxes Other Than Income Taxes	(10)	

Nonoperating Income and Expenses, Net	11	
Total Change in Operating Expenses and Other		(29)
Income Tax Expense		3
Nine Months Ended September 30, 2005 Net Income		$ 116

Net Income decreased $12 million to $116 million in 2005. The decrease is primarily due to a $39 million increase in Asset Impairments and Related Charges partially offset by an increase in gross margin of $14 million and an $11 million increase in Nonoperating Income and Expenses, Net.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins were $7 million higher than the prior period primarily due to favorable weather partially offset by lower fuel margins.
- Off-system Sales margins increased $21 million primarily due to increased AEP Power Pool physical sales and favorable optimization activity.
- Transmission Revenues decreased $15 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.

Operating Expenses and Other changed between years as follows:

- Asset Impairments and Related Charges increased $39 million due to the commitment to a plan to retire units 1 and 2 at our Conesville Plant. In September, we formally requested permission from PJM to retire two units effective December 29, 2005. We received preliminary approval on October 21, 2005.
- Depreciation and Amortization expense decreased $8 million primarily due to the order in the rate stabilization plan which resulted in a 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.
- Taxes Other Than Income Taxes increased $10 million due to an increase in property tax accruals as a result of increased property values. The increase is also a result of increased state excise taxes due to higher KWH sales.
- Nonoperating Income and Expenses, Net increased $11 million due to the establishment of a regulatory asset for carrying costs on environmental capital expenditures as a result of the rate stabilization plan order and increased interest income from the corporate borrowing program.

Income Tax

The effective tax rates for the nine months ended September 2005 and 2004 were 34.7% and 33.6%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

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	A3	BBB	A-

Financing Activity

There were no long-term debt issuances or retirements during the first nine months of 2005.

In October 2005, we issued $250 million of 5.85% Senior Notes, Series F, due in October 2035.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end.

Significant Factors

Monongahela Power Company

In June 2005, the PUCO ordered us to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, we agreed to terms of a transaction, which includes the transfer to us of Monongahela Power's Ohio customer base and the assets that serve those customers for an estimated sales price of approximately $45 million. The net assets are being acquired at net book value. The sale price will be adjusted based on book values of the acquired assets and certain related liabilities at the closing date. In addition, we will pay $10 million to compensate Monongahela Power for its termination of certain generation cost recovery litigation in Ohio. We are proposing that the $10 million payment be recorded as a regulatory asset and recovered from large commercial and industrial customers in the Monongahela Power Ohio service territory over approximately 5 years with a carrying cost.

Also included in the proposed transaction is a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007. We are proposing that beginning June 1, 2007, we will acquire power on the market to meet the needs of the acquired customers through December 31, 2008 (the end of the Rate Stabilization Plans (RSP) period). We have proposed a generation surcharge to be applied to all of our customers to recover the difference between the cost of power included in our generation rates and the higher Allegheny and subsequent market-based purchased power cost to meet the power requirements of the customers acquired from Monongahela Power through the end of the RSP period. We are proposing to institute a true-up mechanism with over/under-recovery deferral accounting for any difference between the surcharge recoveries and the actual cost differential. We have also requested permission to defer with a carrying cost incremental costs associated with the transaction for future recovery in our next distribution rate case. Hearings at the PUCO were held in September 2005. If the transaction is approved by the PUCO, we expect to close the proposed transaction in December 2005. Management is unable to predict the ultimate effect of this transaction on revenues, results of operations, cash flows and financial condition.

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 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.

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

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	30,919
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(7,681)
Fair Value of New Contracts When Entered During the Period (b)		599
Net Option Premiums Paid/(Received) (c)		(395)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		15,294
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		229
Total MTM Risk Management Contract Net Assets		38,965
Net Cash Flow Hedge Contracts (f)		(8,013)
DETM Assignment (g)		(8,932)
Total MTM Risk Management Contract Net Assets at September 30, 2005	$	22,020

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. 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.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2005.

(d) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk