KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 531,343	$ 448,961	$ 412,667	$ 391,516	$ 394,021
Operating Income	$ 60,831	$ 63,339	$ 70,749	$ 57,579	$ 58,824
Income Before Cumulative Effect of Accounting Change	$ 20,809	$ 25,905	$ 33,464	$ 20,567	$ 21,565
Cumulative Effect of Accounting Change, Net of Tax	-	-	(1,134)	-	-
Net Income	$ 20,809	$ 25,905	$ 32,330	$ 20,567	$ 21,565
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 1,414,426	$ 1,367,138	$ 1,355,315	$ 1,301,332	$ 1,134,149
Accumulated Depreciation and Amortization	425,817	398,608	382,022	373,874	360,531
Net Property, Plant and Equipment	$ 988,609	$ 968,530	$ 973,293	$ 927,458	$ 773,618
Total Assets	$ 1,320,026	$ 1,243,247	$ 1,221,634	$ 1,188,342	$ 1,022,833
Long-term Debt (a)	$ 486,990	$ 508,310	$ 487,602	$ 466,632	$ 346,093
Common Shareholder's Equity	$ 347,841	$ 320,980	$ 317,138	$ 298,018	$ 256,130
Obligations Under Capital Leases (a)	$ 3,168	$ 4,363	$ 5,292	$ 7,248	$ 9,583

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 176,000 retail customers in our service territory in eastern Kentucky. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold. As a result of CSPCo's acquisition of the Waterford Plant (offset by the retirement of Conesville Plant Units 1 and 2) and APCo's acquisition of the Ceredo Generating Station, we, as a member with a generating capacity deficit, expect to incur increased capacity charges in 2006. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed 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 the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 26
Changes in Gross Margin:		
Retail Margins	(3)	
Off-system Sales	14	
Transmission Revenues	(3)	
Other Revenues	(4)	
Total Change in Gross Margin		4
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(5)	
Depreciation and Amortization	(1)	
Total Change in Operating Expenses and Other		(6)
Income Tax Expense		(3)
Year Ended December 31, 2005		$ 21

Income Before Cumulative Effect of Accounting Change decreased by $5 million to $21 million in 2005 in comparison to 2004. The key driver of the decrease was a $6 million increase in Operating Expenses and Other.

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 decreased by $3 million in comparison to 2004 primarily due to our higher MLR share caused by the increase in our peak demand that was established in January 2005 resulting in an increase in capacity payments under the Interconnection Agreement. This decrease was partially offset by an increase in retail sales due to favorable weather conditions and an increase in industrial sales.
- Off-system Sales margins for 2005 increased by $14 million compared to 2004 primarily due to increased AEP Power Pool sales.
- Transmission Revenues decreased $3 million primarily due to the elimination of revenues related to through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4.
- Other Revenues decreased $4 million due primarily to a $3 million adjustment of the Demand Side Management Program regulatory asset in March 2005.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $5 million primarily due to a $3 million increase in costs associated with the AEP Transmission Equalization Agreement and a $2 million increase in system dispatch costs related to our operation in PJM.

Income Taxes

The increase in income tax expense of $3 million is primarily due to the recording of the tax return adjustments.

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

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 6.0	$ -	$ -	$ -	$ 6.0
Interest on Long-term Debt (b)	25.2	31.3	10.5	97.5	164.5
Long-term Debt (c)	39.8	352.4	-	95.0	487.2
Capital Lease Obligations (d)	1.3	1.7	0.4	0.1	3.5
Noncancelable Operating Leases (d)	1.8	2.8	2.1	2.0	8.7
Fuel Purchase Contracts (e)	128.2	75.9	-	-	204.1
Energy and Capacity Purchase Contracts (f)	0.1	0.1	-	-	0.2
Construction Contracts for Capital Assets (g)	32.5	-	-	-	32.5
Total	$ 234.9	$ 464.2	$ 13.0	$ 194.6	$ 906.7

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 15.
(e) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

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 if the loss 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. 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 beginning on page M-1 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" 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 balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Balance Sheet
As of December 31, 2005
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 31,180	$ 257	$ -	$ 31,437
Noncurrent Assets	41,810	-	-	41,810
Total MTM Derivative Contract Assets	72,990	257	-	73,247
Current Liabilities	(27,586)	(1,005)	(179)	(28,770)
Noncurrent Liabilities	(31,886)	(663)	(2,753)	(35,302)
Total MTM Derivative Contract Liabilities	(59,472)	(1,668)	(2,932)	(64,072)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 13,518	$ (1,411)	$ (2,932)	$ 9,175

(a) See "Natural Gas Contracts with DETM" section of Note 17.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 12,691
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	73
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	(337)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	443
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	648
Total MTM Risk Management Contract Net Assets	13,518
Net Cash Flow & Fair Value Hedge Contracts	(1,411)
DETM Assignment (d)	(2,932)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 9,175

(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) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory

liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(d) See "Natural Gas Contracts with DETM" section of Note 17.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

**Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)**

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 1,639	$ 917	$ 265	$ -	$ -	$ -	$ 2,821
Prices Provided by Other External Sources – OTC Broker Quotes (a)	4,324	3,116	2,907	1,461	-	-	11,808
Prices Based on Models and Other Valuation Methods (b)	(2,369)	(965)	(522)	778	1,861	106	(1,111)
Total	$ 3,594	$ 3,068	$ 2,650	$ 2,239	$ 1,861	$ 106	$ 13,518

(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 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 derivative transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. 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 required to be marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 569	$ 244	$ 813
Changes in Fair Value	81	-	81
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(1,002)	(86)	(1,088)
Ending Balance in AOCI December 31, 2005	$ (352)	$ 158	$ (194)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $207 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 December 31, 2005, 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 years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$174	$289	$138	$50	$135	$442	$191	$65

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 $13 million and $16 million at December 31, 2005 and 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 operations or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 458,858	$ 397,581	$ 361,198
Sales to AEP Affiliates	70,803	48,717	49,466
Other	1,682	2,663	2,003
TOTAL	531,343	448,961	412,667
EXPENSES			
Fuel and Other Consumables for Electric Generation	142,672	103,881	78,974
Purchased Electricity for Resale	7,213	3,407	963
Purchased Electricity from AEP Affiliates	176,350	140,758	141,690
Other Operation	59,024	51,782	44,866
Maintenance	30,652	32,802	27,328
Depreciation and Amortization	45,110	43,847	39,309
Taxes Other Than Income Taxes	9,491	9,145	8,788
TOTAL	470,512	385,622	341,918
OPERATING INCOME	60,831	63,339	70,749
Other Income (Expense):			
Interest Income	880	462	39
Allowance for Equity Funds Used During Construction	305	245	971
Interest Expense	(29,071)	(29,470)	(28,620)
INCOME BEFORE INCOME TAXES	32,945	34,576	43,139
Income Tax Expense	12,136	8,671	9,675
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	20,809	25,905	33,464
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, Net of Tax	-	-	(1,134)
NET INCOME	$ 20,809	$ 25,905	$ 32,330

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

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

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 50,450	$ 208,750	$ 48,269	$ (9,451)	$ 298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL					281,570
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $53				98	98
Minimum Pension Liability, Net of Tax of $1,691				3,140	3,140
NET INCOME			32,330		32,330
TOTAL COMPREHENSIVE INCOME					35,568
DECEMBER 31, 2003	50,450	208,750	64,151	(6,213)	317,138
Common Stock Dividends			(19,501)		(19,501)
TOTAL					297,637
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $212				393	393
Minimum Pension Liability, Net of Tax of $1,592				(2,955)	(2,955)
NET INCOME			25,905		25,905
TOTAL COMPREHENSIVE INCOME					23,343
DECEMBER 31, 2004	50,450	208,750	70,555	(8,775)	320,980
Common Stock Dividends			(2,500)		(2,500)
TOTAL					318,480
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $542				(1,007)	(1,007)
Minimum Pension Liability, Net of Tax of $5,147				9,559	9,559
NET INCOME			20,809		20,809
TOTAL COMPREHENSIVE INCOME					29,361
DECEMBER 31, 2005	$ 50,450	$ 208,750	$ 88,864	$ (223)	$ 347,841

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

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 526	$ 132
Advances to Affiliates	-	16,127
Accounts Receivable:		
Customers	26,533	22,130
Affiliated Companies	23,525	23,046
Accrued Unbilled Revenues	6,311	7,340
Miscellaneous	35	94
Allowance for Uncollectible Accounts	(147)	(34)
Total Accounts Receivable	56,257	52,576
Fuel	8,490	6,551
Materials and Supplies	10,181	9,385
Risk Management Assets	31,437	19,845
Margin Deposits	6,895	1,960
Accrued Tax Benefits	6,598	-
Prepayments and Other	6,324	1,993
TOTAL	126,708	108,569
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	472,575	462,641
Transmission	386,945	385,667
Distribution	456,063	438,766
Other	63,382	63,520
Construction Work in Progress	35,461	16,544
Total	1,414,426	1,367,138
Accumulated Depreciation and Amortization	425,817	398,608
TOTAL - NET	988,609	968,530
OTHER NONCURRENT ASSETS		
Regulatory Assets	117,432	118,407
Long-term Risk Management Assets	41,810	19,067
Deferred Charges and Other	45,467	28,674
TOTAL	204,709	166,148
TOTAL ASSETS	$ 1,320,026	$ 1,243,247

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

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 6,040	$ -
Accounts Payable:		
General	32,454	20,080
Affiliated Companies	29,326	24,899
Long-term Debt Due Within One Year – Affiliated	39,771	-
Risk Management Liabilities	28,770	17,205
Customer Deposits	21,643	12,309
Accrued Taxes	8,805	9,248
Other	21,524	19,935
TOTAL	188,333	103,676
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	427,219	428,310
Long-term Debt – Affiliated	20,000	80,000
Long-term Risk Management Liabilities	35,302	13,484
Deferred Income Taxes	234,719	227,536
Regulatory Liabilities and Deferred Investment Tax Credits	56,794	47,994
Deferred Credits and Other	9,818	21,267
TOTAL	783,852	818,591
TOTAL LIABILITIES	972,185	922,267
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $50 Par Value Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	88,864	70,555
Accumulated Other Comprehensive Income (Loss)	(223)	(8,775)
TOTAL	347,841	320,980
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,320,026	$ 1,243,247

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

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 20,809	$ 25,905	$ 32,330
Adjustments for Noncash Items:			
Depreciation and Amortization	45,110	43,847	39,309
Deferred Income Taxes	10,555	12,774	20,107
Cumulative Effect of Accounting Change, Net of Tax	-	-	1,134
Mark-to-Market of Risk Management Contracts	(3,465)	1,020	15,112
Pension Contributions to Qualified Plan Trusts	(18,894)	(451)	(1,614)
Change in Other Noncurrent Assets	(419)	(6,902)	(16,613)
Change in Other Noncurrent Liabilities	3,844	9,126	8,720
Changes in Components of Working Capital:			
Accounts Receivable, Net	(3,681)	(1,177)	2,445
Fuel, Materials and Supplies	(2,735)	2,724	1,077
Accounts Payable	13,184	(1,745)	(31,000)
Accrued Taxes, Net	(7,041)	1,919	8,582
Customer Deposits	9,334	2,415	1,846
Other Current Assets	(9,261)	474	(1,055)
Other Current Liabilities	1,589	65	(3,505)
Net Cash Flows From Operating Activities	58,929	89,994	76,875
INVESTING ACTIVITIES			
Construction Expenditures	(56,979)	(36,957)	(94,836)
Change in Other Cash Deposits, Net	(5)	-	-
Change in Advances to Affiliates, Net	16,127	(16,127)	-
Proceeds from Sale of Assets	300	1,538	967
Net Cash Flows Used For Investing Activities	(40,557)	(51,546)	(93,869)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	-	-	74,263
Issuance of Long-term Debt – Affiliated	-	20,000	-
Change in Advances from Affiliates, Net	6,040	(38,096)	14,710
Retirement of Long-term Debt – Nonaffiliated	-	-	(40,000)
Retirement of Long-term Debt – Affiliated	(20,000)	-	(15,000)
Principal Payments for Capital Lease Obligations	(1,518)	(1,605)	(1,949)
Dividends Paid on Common Stock	(2,500)	(19,501)	(16,448)
Net Cash Flows From (Used For) Financing Activities	(17,978)	(39,202)	15,576
Net Increase (Decrease) in Cash and Cash Equivalents	394	(754)	(1,418)
Cash and Cash Equivalents at Beginning of Period	132	886	2,304
Cash and Cash Equivalents at End of Period	$ 526	$ 132	$ 886

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $27,354,000, $28,367,000 and $26,988,000 and for income taxes was $11,655,000, $(3,233,000) and $(17,574,000) in 2005, 2004 and 2003, respectively. Noncash acquisitions under capital leases were $419,000, $925,000 and $344,000 in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of $6,553,000, $2,936,000 and $1,662,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively.

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2005 and 2004, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 11 to the financial statements, respectively, the Company adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003, and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006