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 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)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 112,753	$ 209	$ -	$ 112,962
Noncurrent Assets	102,413	230	-	102,643
Total MTM Derivative Contract Assets	215,166	439	-	215,605
Current Liabilities	(98,767)	(8,204)	(2,122)	(109,093)
Noncurrent Liabilities	(77,434)	(248)	(6,810)	(84,492)
Total MTM Derivative Contract Liabilities	(176,201)	(8,452)	(8,932)	(193,585)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 38,965	$ (8,013)	$ (8,932)	$ 22,020

(a) Does not include Cash Flow 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	$ (1,427)	$ 6,865	$ 577	$ 316	$ -	$ -	$ 6,331
Prices Provided by Other External Sources - OTC Broker Quotes (a)	10,978	7,619	10,503	4,190	613	-	33,903
Prices Based on Models and Other Valuation Methods (b)	(1,104)	(6,305)	(3,717)	2,197	4,595	3,065	(1,269)
Total	$ 8,447	$ 8,179	$ 7,363	$6,703	$5,208	$3,065	$38,965

(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. $4.4 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow 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.

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
Beginning Balance December 31, 2004	$ 1,393
Changes in Fair Value (a)	(4,871)
Reclassifications from AOCI to Net Income (b)	(1,918)
Ending Balance September 30, 2005	$ (5,396)

(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 $5,384 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**
$503	$686	$323	$172	$332	$1,083	$467	$160

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 $45 million and $48 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.

COLUMBUS SOUTHERN 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	$ 425,738	$ 369,329	$ 1,105,863	$ 1,050,794
Sales to AEP Affiliates	25,440	21,796	70,451	61,748
TOTAL	451,178	391,125	1,176,314	1,112,542
OPERATING EXPENSES				
Fuel for Electric Generation	62,470	49,732	170,380	142,528
Fuel from Affiliates for Electric Generation	-	-	-	10,603
Purchased Electricity for Resale	9,016	5,389	26,922	14,839
Purchased Electricity from AEP Affiliates	109,274	96,193	284,221	263,614
Other Operation	66,217	60,657	173,287	177,920
Maintenance	21,863	17,417	63,947	60,187
Asset Impairments and Other Related Charges	39,109	-	39,109	-
Depreciation and Amortization	37,454	37,933	102,985	111,196
Taxes Other Than Income Taxes	43,342	34,017	112,417	102,069
Income Taxes	19,432	24,525	57,901	65,187
TOTAL	408,177	325,863	1,031,169	948,143
OPERATING INCOME	43,001	65,262	145,145	164,399
Nonoperating Income	4,865	1,681	10,653	7,298
Carrying Costs Income	1,800	127	8,716	358
Nonoperating Expenses	427	444	2,169	2,037
Nonoperating Income Tax Expense (Credit)	1,506	(383)	3,913	(92)
Interest Charges	13,508	14,439	42,088	41,666
NET INCOME	34,225	52,570	116,344	128,444
Preferred Stock Dividend Requirements including Capital Stock Expense and Other Expense	254	254	2,366	762

EARNINGS APPLICABLE TO

COMMON STOCK	$ 33,971	$ 52,316	$ 113,978	$ 127,682

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the 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	$ 41,026	$576,400	$ 326,782	$ (46,327)	$897,881
Common Stock Dividends			(93,750)		(93,750)
Capital Stock Expense		762	(762)		-
TOTAL					804,131
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,248				(2,317)	(2,317)
NET INCOME			128,444		128,444
TOTAL COMPREHENSIVE INCOME					126,127
SEPTEMBER 30, 2004	$ 41,026	$577,162	$ 360,714	$ (48,644)	$930,258
DECEMBER 31, 2004	$ 41,026	$577,415	$ 341,025	$ (60,816)	$898,650
Common Stock Dividends			(85,500)		(85,500)
Capital Stock Expense and Other		2,366	(2,366)		-
TOTAL					813,150
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,655				(6,789)	(6,789)
NET INCOME			116,344		116,344
TOTAL COMPREHENSIVE INCOME					109,555
SEPTEMBER 30, 2005	$ 41,026	$579,781	$ 369,503	$ (67,605)	$922,705

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN 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	$ 1,849,869	$ 1,658,552
Transmission	446,356	432,714
Distribution	1,325,806	1,300,252
General	161,915	167,985
Construction Work in Progress	120,624	131,743
Total	3,904,570	3,691,246
Accumulated Depreciation and Amortization	1,479,077	1,471,950
TOTAL - NET	2,425,493	2,219,296
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	21,780	22,322
Other Investments	4,094	5,147
TOTAL	25,874	27,469
CURRENT ASSETS		
Cash and Cash Equivalents	1,068	25
Other Cash Deposits	-	33
Advances to Affiliates	-	141,550
Accounts Receivable:		
Customers	46,411	41,130
Affiliated Companies	73,450	72,854
Accrued Unbilled Revenues	19,987	19,580
Miscellaneous	2,432	1,145
Allowance for Uncollectible Accounts	(498)	(674)
Fuel	29,054	34,026
Materials and Supplies	25,861	37,137
Risk Management Assets	112,962	46,631
Margin Deposits	27,230	4,848
Prepayments and Other	17,501	11,499
TOTAL	355,458	409,784
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		

SFAS 109 Regulatory Asset, Net	18,131	16,481
Transition Regulatory Assets	151,851	156,676
Unamortized Loss on Reacquired Debt	12,581	13,155
Other	42,223	25,691
Long-term Risk Management Assets	102,643	46,735
Deferred Property Taxes	17,711	64,754
Deferred Charges and Other	50,807	49,855
TOTAL	395,947	373,347
TOTAL ASSETS	$ 3,202,772	$ 3,029,896

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN 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 - 24,000,000 shares		
Outstanding - 16,410,426 shares	$ 41,026	$ 41,026
Paid-in Capital	579,781	577,415
Retained Earnings	369,503	341,025
Accumulated Other Comprehensive Income (Loss)	(67,605)	(60,816)
Total Common Shareholder's Equity	922,705	898,650
Preferred Stock - No Shares Outstanding	-	-
Authorized - 2,500,000 shares at $100 par value		
Authorized - 7,000,000 shares at $25 par value		
Total Shareholder's Equity	922,705	898,650
Long-term Debt:		
Nonaffiliated	851,822	851,626
Affiliated	100,000	100,000
Total Long-term Debt	951,822	951,626
TOTAL	1,874,527	1,850,276
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	36,000	36,000
Advances from Affiliates	138,541	-
Accounts Payable:		
General	57,904	63,606
Affiliated Companies	53,489	45,745
Customer Deposits	55,651	24,890
Taxes Accrued	102,791	195,284
Interest Accrued	8,300	16,320
Risk Management Liabilities	109,093	42,172
Obligations Under Capital Leases	3,057	3,854
Other	22,875	24,338
TOTAL	587,701	452,209
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	437,994	464,545

Regulatory Liabilities:		
Asset Removal Costs	108,265	103,104
Deferred Investment Tax Credits	25,953	27,933
Other	24,009	-
Employee Benefits and Pension Obligations	25,321	62,778
Long-term Risk Management Liabilities	84,492	32,731
Obligations Under Capital Leases	6,873	8,660
Asset Retirement Obligations	12,222	11,585
Deferred Credits and Other	15,415	16,075
TOTAL	740,544	727,411
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 3,202,772	$ 3,029,896

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN 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	$ 116,344	$ 128,444
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	102,985	111,196
Deferred Income Taxes	(9,441)	10,210
Deferred Investment Tax Credits	(1,980)	(2,133)
Impairment of Long-Lived Assets	39,109	-
Pension and Postemployment Benefit Reserves	374	(1,894)
Deferred Property Taxes	47,640	46,512
Mark-to-Market of Risk Management Contracts	(12,768)	10,130
Carrying Costs Income	(8,716)	(358)
Pension Contributions	(37,831)	(24)
Gain on Sale of Assets	(1,560)	(2,315)
Change in Other Noncurrent Assets	(20,439)	(33,811)
Change in Other Noncurrent Liabilities	13,710	7,362
Changes in Components of Working Capital:		
Accounts Receivable, Net	(7,747)	24,242
Fuel, Materials and Supplies	19,345	(13,545)
Accounts Payable	3,023	(13,269)
Taxes Accrued	(94,788)	2,115
Customer Deposits	30,761	6,684
Interest Accrued	(8,020)	(8,640)
Other Current Assets	(28,384)	2,958
Other Current Liabilities	(3,259)	(2,903)
Net Cash Flows From Operating Activities	138,358	270,961
INVESTING ACTIVITIES		
Construction Expenditures	(118,222)	(103,257)
Change in Other Cash Deposits, Net	33	666
Purchase of Waterford Plant	(218,356)	-
Proceeds from Sale of Assets	4,639	3,392
Net Cash Flows Used For Investing Activities	(331,906)	(99,199)
FINANCING ACTIVITIES		
Changes in Advances to/from Affiliates, Net	280,091	(164,888)
Dividends Paid on Common Stock	(85,500)	(93,750)

Issuance of Long-term Debt - Nonaffiliated	-	90,057
Issuance of Long-term Debt - Affiliated	-	100,000
Retirement of Long-term Debt	-	(103,245)
Net Cash Flows From (Used For) Financing Activities	194,591	(171,826)
Net Increase (Decrease) in Cash and Cash Equivalents	1,043	(64)
Cash and Cash Equivalents at Beginning of Period	25	3,377
Cash and Cash Equivalents at End of Period	$ 1,068	$ 3,313

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $50,095,000 and $46,034,000 and for income taxes was $109,382,000 and $(5,282,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $520,000 and $731,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $(981,000) and $(2,266,000) in 2005 and 2004, respectively. In connection with the acquisition of the Waterford Plant in September 2005, we assumed $2,295,000 of liabilities.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

The condensed notes to CSPCo'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 CSPCo.

	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
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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

INDIANA MICHIGAN 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		$ 52
Changes in Gross Margin:		
Retail Margins	32	
Transmission Revenues	(6)	
Total Change in Gross Margin		26
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(17)	
Taxes Other Than Income Taxes	(7)	
Nonoperating Income and Expenses, Net	4	
Total Change in Operating Expenses and Other		(20)
Income Tax Expense		(5)
Third Quarter of 2005 Net Income		$ 53

Net Income increased $1 million to $53 million in the third quarter of 2005. The key drivers of the increase were a $26 million increase in gross margin partially offset by a $17 million increase in Other Operation and Maintenance expenses and a $7 million increase in Taxes Other Than Income Taxes.

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

- Retail Margins increased $32 million primarily due to increases in retail sales to residential and commercial customers and capacity settlement payments received under the Interconnection Agreement related to the increase in an affiliate's peak load. Increased retail sales primarily reflect warmer summer weather. Cooling degree days were 17% higher than normal and 67% higher than 2004.
- Transmission Revenues decreased $6 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:

- Other Operation and Maintenance expenses increased $17 million primarily due to a $9 million increase related to higher costs of labor and allowances for power generation and a $4 million increase in distribution maintenance expense for overhead power lines.
- Taxes Other Than Income Taxes increased due to a $5 million increase in real & personal property taxes and a $2 million increase in payroll-related taxes related to higher labor costs.
- Nonoperating Income and Expenses, Net increased due to $3 million of favorable results from favorable optimization activities.

Income Tax

The effective tax rates for the third quarter of 2005 and 2004 were 38.0% and 34.5%, 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, state income taxes and federal income tax adjustments. 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		$ 122
Changes in Gross Margin:		
Retail Margins	48	
Transmission Revenues	(17)	
Off-system Sales and Other Revenues	2	
Total Change in Gross Margin		33
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(20)	
Taxes Other Than Income Taxes	(9)	
Interest Charges	4	
Total Change in Operating Expenses and Other		(25)
Income Tax Expense		(2)
Nine Months Ended September 30, 2005 Net Income		$ 128

Net Income increased $6 million to $128 million in the first nine months of 2005. The key driver of the increase was a $33 million increase in gross margin partially offset by a $20 million increase in Other Operation and Maintenance expenses.

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

- Retail Margins increased $48 million primarily due to a $33 million increase in capacity settlement payments received under the Interconnection Agreement related to the increase in an affiliate's peak load and higher residential revenue of $20 million reflecting warm summer weather partially offset by an increase in unrecovered fuel costs due to fuel caps in our Indiana jurisdiction.
- Transmission Revenues decreased $17 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 change

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $20 million primarily due to a $9 million increase in distribution maintenance mainly related to January 2005 storm damage, a $5 million increase in system dispatch costs related to our operation in PJM and $4 million of accruals for employee severance costs partially offset by the settlement and cancellation of COLI policies in February 2005.
- Taxes Other Than Income Taxes increased $9 million primarily due to a $6 million increase in real and personal property taxes and a $3 million increase in payroll-related taxes.
- Interest Charges decreased $4 million primarily due to lower long-term debt outstanding and lower interest rates.

Income Tax

The effective tax rates for the nine months ended September 2005 and 2004 were 35.7% and 36.1%, 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, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative periods.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Cash Flow

Cash flows for the first nine months of 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	

Cash and Cash Equivalents at Beginning of Period	$ 465	$ 3,899
Cash Flows From (Used For):		
Operating Activities	204,343	414,654
Investing Activities	(176,571)	(129,398)
Financing Activities	(27,506)	(286,774)
Net Increase (Decrease) in Cash and Cash Equivalents	266	(1,518)
Cash and Cash Equivalents at End of Period	$ 731	$ 2,381

Operating Activities

Net Cash Flows From Operating Activities were $204 million for the first nine months of 2005. We produced Net Income of $128 million during the period including noncash expense items of $163 million for depreciation, amortization and accretion. 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 most significant activities in these asset and liability accounts were contributions of $46 million to our pension trust and $137 million of federal income tax payments.

Net Cash Flows From Operating Activities were $415 million during 2004. We produced Net Income of $122 million during the period and noncash expense items of $158 million for depreciation, amortization and accretion. The other changes in assets and liabilities represent items that had a cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items; the most significant relates to Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP Consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments.

Investing Activities

Net Cash Flows Used For Investing Activities during 2005 were $177 million due primarily to Construction Expenditures. Construction Expenditures were primarily for nuclear generation, transmission and distribution assets to upgrade or replace equipment and improve reliability. For the remainder of 2005, we expect our construction expenditures to be approximately $130 million.

Net Cash Flows Used For Investing Activities were $129 million during 2004 for Construction Expenditures.

Financing Activities

Net Cash Flows Used For Financing Activities were $28 million during 2005. We used cash of $61 million to retire preferred stock and $52 million to pay common dividends. These activities were supported by additional borrowing from the Utility Money Pool of $86 million. There were no long-term debt issuances or retirements during the first nine months of 2005.

Net Cash Flows Used For Financing Activities were $287 million during 2004. We used cash from operations to retire long-term debt and pay common dividends.

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.

Off-Balance Sheet Arrangements

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our current policy restricts the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and sales of customer accounts receivable that are entered in the normal course of business. Our off-balance sheet arrangements have not changed significantly since year-end. For complete information on our off-balance sheet arrangements, including the lease of Rockport Plant Unit 2, see "Off-balance Sheet Arrangements" in the "Management's Financial Discussion and Analysis" section of our 2004 Annual Report.

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 $61 million retirement of preferred stock and entering a long-term power contract.

During October 2005, we entered into a 20-year power agreement effective January 1, 2006, with Indiana Municipal Power Agency (IMPA). The 150 megawatt agreement is expected to generate annual revenue of approximately $55 million. The contract contains routine remedy clauses in case of default.

Significant Factors

Nuclear Licenses

In August 2005, the Nuclear Regulatory Commission approved the renewal of operating licenses for the two generating units at our Cook Plant. The licenses now expire in 2034 for Unit 1 and 2037 for Unit 2. Based on this renewal, we adjusted our asset retirement obligation liability and related plant asset. We are evaluating the effect of relicensing on current depreciation rates and decommissioning funding. If any changes are necessary, we will need IURC and MPSC approval.

Spent Nuclear Fuel Litigation

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, we, along with a number of nonaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, we filed a complaint in the U.S.

Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In January 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability. The case was tried in March 2004 on the issue of damages owed to us by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against us and denied damages, ruling that pre-breach and post-breach damages are not recoverable in a partial breach case. In July 2004, we appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. In September 2005, the U.S. Court of Appeals ruled that the trial court erred in ruling that pre-breach damages in a partial breach case are per se not recoverable, but denied us our pre-breach damages on the facts alleged. The Court of Appeals also ruled that the trial court did not err in determining that post-breach damages are not recoverable in a partial breach case, but determined that we may recover our post-breach damages in later suits as the costs are incurred.

Indiana Settlement Agreement

Our fuel and base rates in Indiana were frozen through a prior agreement. In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005 and filed the agreement with the IURC on March 14, 2005. The IURC approved the agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate that includes 8.609 mills per KWH reflected in base rates. The settlement provides that the total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, we began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor will be adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), the ratio of the sum of fuel and one half maintenance expenses incurred by the pool members to the total kilowatt-hours of net generation, excluding us, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total cumulative actual fuel costs (except during a Cook Plant outage of greater than 60 days) are less than the cap prices, the savings will be credited to customers over the next two fuel adjustment clause filings. Cumulative net fuel costs in excess of the capped prices cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, we will receive credit for 30% of the savings produced by that performance.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, we may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond our control occurs or a material impact on us occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

We experienced a cumulative under-recovery for the period March 2004 through September 2005 of $10 million. Since we expect that its cumulative fuel costs through the end of the fuel cap period will exceed the capped fuel rates, the $10 million was recorded as fuel expense. If future fuel costs per KWH through June 30, 2007 continue to exceed the caps, or if the base rate cap precludes us from seeking timely rate increases to recover increases in its cost of service through June 30, 2007, future results of operations and cash flows would be adversely affected.

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	$ 34,573
(Gain) Loss from Contracts Realized/Settled During the Period (a)	216
Fair Value of New Contracts When Entered During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(648)
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	1,330
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	4,234
Total MTM Risk Management Contract Net Assets	39,705
Net Cash Flow and Fair Value Hedge Contracts (f)	(6,813)
DETM Assignment (g)	(9,123)
Total MTM Risk Management Contract Net Assets at September 30, 2005	$ 23,769

(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	$ 115,223	$ 2,146	$ -	$ 117,369
Noncurrent Assets	105,169	235	-	105,404
Total MTM Derivative Contract Assets	220,392	2,381	-	222,773
Current Liabilities	(101,169)	(8,697)	(2,167)	(112,033)
Noncurrent Liabilities	(79,518)	(497)	(6,956)	(86,971)
Total MTM Derivative Contract Liabilities	(180,687)	(9,194)	(9,123)	(199,004)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 39,705	$ (6,813)	$ (9,123)	$ 23,769

(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	$ (1,458)	$ 7,012	$ 590	$ 323	$ -	$ -	$ 6,467
Prices Provided by Other External Sources - OTC Broker Quotes (a)	11,152	7,712	11,045	4,280	626	-	34,815
Prices Based on Models and Other Valuation Methods (b)	(1,129)	(6,605)	(3,856)	2,189	4,694	3,130	(1,577)
Total	$ 8,565	$ 8,119	$ 7,779	$6,792	$5,320	$3,130	$39,705

(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. $4.4 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 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	Interest Rate	Total
Beginning Balance December 31, 2004	$ 1,558	$ (5,634)	$ (4,076)
Changes in Fair Value (a)	(4,907)	1,256	(3,651)
Reclassifications from AOCI to Net Income (b)	(2,162)	428	(1,734)
Ending Balance September 30, 2005	$ (5,511)	$ (3,950)	$ (9,461)

(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 $5,950 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
$514	$701	$330	$176	$371	$1,211	$522	$178

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 $52 million and $53 million at September 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire 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.

INDIANA MICHIGAN 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	$ 409,282	$ 372,556	$ 1,128,374	$ 1,067,144
Sales to AEP Affiliates	84,207	70,378	244,616	193,048
TOTAL	493,489	442,934	1,372,990	1,260,192
OPERATING EXPENSES				
Fuel for Electric Generation	89,334	75,086	245,500	204,709
Purchased Electricity for Resale	11,784	10,063	35,786	22,617
Purchased Electricity from AEP Affiliates	82,763	74,498	228,756	203,291
Other Operation	109,210	100,535	300,212	307,501
Maintenance	42,300	33,737	144,988	118,055
Depreciation and Amortization	42,726	43,170	127,695	128,581
Taxes Other Than Income Taxes	17,007	10,291	49,624	40,979
Income Taxes	31,403	28,072	69,663	67,169
TOTAL	426,527	375,452	1,202,224	1,092,902
OPERATING INCOME	66,962	67,482	170,766	167,290
Nonoperating Income	22,793	20,304	61,999	60,758
Nonoperating Expenses	19,255	20,810	54,506	52,837
Nonoperating Income Tax Expense (Credit)	1,145	(953)	1,558	1,538
Interest Charges	16,343	16,381	48,427	52,087
NET INCOME	53,012	51,548	128,274	121,586
Preferred Stock Dividend Requirements including Capital Stock Expense	86	119	311	356
EARNINGS APPLICABLE TO COMMON STOCK	$ 52,926	$ 51,429	$ 127,963	$ 121,230

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the 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	$ 56,584	$858,694	$ 187,875	$ (25,106)	$1,078,047
Common Stock Dividends			(79,293)		(79,293)
Preferred Stock Dividends			(255)		(255)
Capital Stock Expense		107	(101)		6
TOTAL					998,505
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,720				(8,765)	(8,765)
NET INCOME			121,586		121,586
TOTAL COMPREHENSIVE INCOME					112,821
SEPTEMBER 30, 2004	$ 56,584	$858,801	$ 229,812	$ (33,871)	$1,111,326
DECEMBER 31, 2004	$ 56,584	$858,835	$ 221,330	$ (45,251)	$1,091,498
Common Stock Dividends			(52,000)		(52,000)
Preferred Stock Dividends			(255)		(255)
Capital Stock Expense and Other		2,455	(56)		2,399
TOTAL					1,041,642
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,900				(5,385)	(5,385)
NET INCOME			128,274		128,274
TOTAL COMPREHENSIVE INCOME					122,889
SEPTEMBER 30, 2005	$ 56,584	$861,290	$ 297,293	$ (50,636)	$1,164,531

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN 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	$ 3,111,119	$ 3,122,883
Transmission	1,024,558	1,009,551
Distribution	1,016,092	990,826
General (including nuclear fuel)	259,800	275,622
Construction Work in Progress	264,049	163,515
Total	5,675,618	5,562,397
Accumulated Depreciation and Amortization	2,698,727	2,603,479
TOTAL - NET	2,976,891	2,958,918
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,120,190	1,053,439
Nonutility Property, Net	49,035	50,440
Other Investments	13,262	21,848
TOTAL	1,182,487	1,125,727
CURRENT ASSETS		
Cash and Cash Equivalents	731	465
Other Cash Deposits	-	46
Advances to Affiliates	-	5,093
Accounts Receivable:		
Customers	66,701	62,608
Affiliated Companies	106,996	124,134
Miscellaneous	2,772	4,339
Allowance for Uncollectible Accounts	(16)	(187)
Fuel	20,892	27,218
Materials and Supplies	105,365	103,342
Risk Management Assets	117,369	52,141
Margin Deposits	27,812	5,400
Prepayments and Other	27,607	10,541
TOTAL	476,229	395,140
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		

SFAS 109 Regulatory Asset, Net	124,979	147,167
Incremental Nuclear Refueling Outage Expenses, Net	33,738	44,244
Unrealized Loss on Forward Commitments	33,285	7,366
Unamortized Loss on Reacquired Debt	22,231	21,039
DOE Decontamination Fund	10,353	14,215
Other	34,042	23,649
Long-term Risk Management Assets	105,404	52,256
Emission Allowances	31,301	27,093
Deferred Property Taxes	12,558	22,372
Deferred Charges and Other Assets	15,912	28,955
TOTAL	423,803	388,356
TOTAL ASSETS	$ 5,059,410	$ 4,868,141

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN 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 - 2,500,000 Shares		
Outstanding - 1,400,000 Shares	$ 56,584	$ 56,584
Paid-in Capital	861,290	858,835
Retained Earnings	297,293	221,330
Accumulated Other Comprehensive Income (Loss)	(50,636)	(45,251)
Total Common Shareholder's Equity	1,164,531	1,091,498
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,084
Total Shareholders' Equity	1,172,615	1,099,582
Long-term Debt	1,317,825	1,312,843
TOTAL	2,490,440	2,412,425
CURRENT LIABILITIES		
Cumulative Preferred Stock Due Within One Year	-	61,445
Advances from Affiliates	81,101	-
Accounts Payable:		
General	98,153	91,472
Affiliated Companies	58,374	51,066
Customer Deposits	57,599	29,366
Taxes Accrued	37,409	123,159
Interest Accrued	22,823	12,465
Risk Management Liabilities	112,033	47,174
Obligations Under Capital Leases	5,501	6,124
Other	87,654	70,237
TOTAL	560,647	492,508
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	292,912	315,730
Regulatory Liabilities:		
Asset Removal Costs	289,405	280,054
Deferred Investment Tax Credits	77,306	82,802
Excess ARO for Nuclear Decommissioning	269,406	245,175
Unrealized Gain on Forward Commitments	65,687	35,534

Other	33,816	33,695
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	63,692	66,472
Long-term Risk Management Liabilities	86,971	36,815
Obligations Under Capital Leases	38,152	44,608
Asset Retirement Obligations	720,532	711,769
Employee Benefits and Pension Obligations	31,388	70,027
Deferred Credits and Other	39,056	40,527
TOTAL	2,008,323	1,963,208
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,059,410	$ 4,868,141

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN 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	$ 128,274	$ 121,586
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	127,695	128,581
Accretion Expense	35,742	29,608
Amortization, Net of Deferrals of Incremental Nuclear Refueling Outage Expenses	10,506	31,195
Deferred Income Taxes	2,269	2,772
Deferred Investment Tax Credits	(5,496)	(5,496)
Deferred Property Taxes	9,814	10,020
Pension Contributions	(46,051)	(2,916)
Mark-to-Market of Risk Management Contracts	(11,275)	10,760
Change in Other Noncurrent Assets	4,873	(21,135)
Change in Other Noncurrent Liabilities	(6,420)	(4,050)
Changes in Components of Working Capital:		
Accounts Receivable, Net	14,441	41,624
Fuel, Materials and Supplies	4,303	(9,391)
Accounts Payable	5,511	(13,238)
Taxes Accrued	(85,750)	55,077
Customer Deposits	28,233	9,115
Interest Accrued	10,358	2,742
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(39,478)	5,230
Other Current Liabilities	(1,670)	4,106
Net Cash Flows From Operating Activities	204,343	414,654
INVESTING ACTIVITIES		
Construction Expenditures	(190,171)	(130,241)
Change in Other Cash Deposits, Net	46	(31)
Proceeds from Sale of Assets	13,554	874
Net Cash Flows Used For Investing Activities	(176,571)	(129,398)
FINANCING ACTIVITIES		
Retirement of Cumulative Preferred Stock	(61,445)	(2,011)
Retirement of Long-term Debt	-	(205,155)

Changes in Advances to/from Affiliates, Net	86,194	(60)
Dividends Paid on Common Stock	(52,000)	(79,293)
Dividends Paid on Cumulative Preferred Stock	(255)	(255)
Net Cash Flows Used For Financing Activities	(27,506)	(286,774)
Net Increase (Decrease) in Cash and Cash Equivalents	266	(1,518)
Cash and Cash Equivalents at Beginning of Period	465	3,899
Cash and Cash Equivalents at End of Period	$ 731	$ 2,381

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $34,999,000 and $46,694,000 and for income taxes was $149,058,000 and $(4,725,000) in 2005 and 2004, respectively. Noncash acquisitions under capital leases were $1,465,000 and $10,092,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $8,478,000 and $(10,646,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

The condensed notes to I&M'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 I&M.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
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

KENTUCKY POWER COMPANY

KENTUCKY POWER 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		$ 6
Changes in Gross Margin:		
Retail Margins	8	
Off-system Sales	1	
Transmission Revenues	(1)	
Total Change in Gross Margin		8
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(4)	
Nonoperating Income and Expenses, Net	1	
Total Change in Operating Expenses and Other:		(3)
Income Tax Expense		(3)
Third Quarter of 2005 Net Income		$ 8

Net Income increased by $2 million to $8 million in the third quarter of 2005 in comparison to the third quarter of 2004. The key driver of the increase was an $8 million increase in gross margin partially offset by a $3 million increase in operating expenses and other and a $3 million increase 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 increased by $8 million in comparison to 2004 primarily due to increases in retail sales to residential customers and the recording of a liability for the over-collection of fuel costs in the third quarter of 2004 that lowered retail margins in the prior year. The increase in retail sales to residential customers was primarily due to a 63% increase in cooling degree days in comparison to 2004. The increase in Retail Margins was partially offset by an increase in capacity settlement payments under the Interconnection Agreement.
- Off-system Sales margins for 2005 increased by $1 million compared to 2004 primarily due to increased AEP Power Pool physical sales.

- Transmission Revenues decreased $1 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" for additional discussion of these FERC rate changes.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $4 million primarily due to distribution line maintenance and system dispatch costs related to our operation in PJM.
- Nonoperating Income and Expenses, Net increased $1 million due to favorable optimization activities.

Income Taxes

The effective tax rates for the third quarter of 2005 and 2004 were 31.1% and 11.4%, 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, amortization of investment tax credits, state income taxes and federal income tax adjustments. 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		$ 22
Changes in Gross Margin:		
Retail Margins	(3)	
Off-system Sales	8	
Transmission Revenues	(4)	
Other Revenues	(1)	
Total Change in Gross Margin		-
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(4)	
Nonoperating Income and Expenses, Net	2	
Total Change in Operating Expenses and Other		(2)
Nine Months Ended September 30, 2005 Net Income		$ 20

Net Income decreased by $2 million to $20 million in the nine months ended September 30, 2005 in comparison to the nine months ended September 30, 2004. The key driver of the decrease was a $2 million increase in operating expenses and other.

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 $3 million in comparison to 2004 primarily due to an increase in capacity settlement payments under the Interconnection Agreement resulting from our higher MLR share caused by the increase in our peak load established in January 2005.
- Off-system Sales margins for 2005 increased by $8 million compared to 2004 primarily due to increased AEP Power Pool physical sales.
- Transmission Revenues decreased $4 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" for additional discussion of these FERC rate changes.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $4 million primarily due to increased transmission charges under the Transmission Equalization Agreement resulting from our higher MLR as well as system dispatch costs related to our operation in PJM.
- Nonoperating Income and Expenses, Net increased $2 million due to favorable optimization activities.

Income Taxes

The effective tax rates for the nine months ended September 2005 and 2004 were 28.5% and 27.4%, 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, amortization of investment tax credits, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative periods.

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

Financing Activity

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

Issuances

None

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable-Affiliated	$ 20,000	6.501	2006

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 $20 million retirement of Notes Payable-Affiliated.

Significant Factors

Rate Filing

On September 26, 2005, we filed a request with the Kentucky Public Service Commission to increase base rates by approximately $65 million to recover increasing costs. A final order is expected in April 2006. We are 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	$	12,691
(Gain) Loss from Contracts Realized/Settled During the Period (a)		36
Fair Value of New Contracts When Entered During the Period (b)		-
Net Option Premiums Paid/(Received) (c)		(171)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		820
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		2,615
Total MTM Risk Management Contract Net Assets		15,991
Net Cash Flow and Fair Value Hedge Contracts (f)		(4,399)
DETM Assignment (g)		(3,666)
Total MTM Risk Management Contract Net Assets at September 30, 2005	$	7,926

(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, storage, 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 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 Balance Sheets
As of September 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 46,287	$ 86	$ -	$ 46,373
Noncurrent Assets	42,060	95	-	42,155
Total MTM Derivative Contract Assets	88,347	181	-	88,528
Current Liabilities	(40,554)	(3,489)	(871)	(44,914)
Noncurrent Liabilities	(31,802)	(1,091)	(2,795)	(35,688)
Total MTM Derivative Contract Liabilities	(72,356)	(4,580)	(3,666)	(80,602)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,991	$ (4,399)	$ (3,666)	$ 7,926

(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 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	$ (586)	$ 2,818	$ 237	$ 130	$ -	$ -	$ 2,599
Prices Provided by Other External Sources - OTC Broker Quotes (a)	4,504	3,125	4,323	1,720	251	-	13,923
Prices Based on Models and Other Valuation Methods (b)	(454)	(2,594)	(1,528)	900	1,887	1,258	(531)
Total	$ 3,464	$ 3,349	$ 3,032	$2,750	$2,138	$1,258	$15,991

(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. $1.8 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 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.

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	Interest Rate	Total
Beginning Balance December 31, 2004	$ 569	$ 244	$ 813
Changes in Fair Value (a)	(1,889)	-	(1,889)
Reclassifications from AOCI to Net Income (b)	(895)	(64)	(959)
Ending Balance September 30, 2005	$ (2,215)	$ 180	$ (2,035)

(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 $2,124 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
$207	$282	$133	$71	$135	$442	$191	$65

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 $13 million and $16 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.

KENTUCKY POWER 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	$ 127,129	$ 100,950	$ 352,083	$ 302,376
Sales to AEP Affiliates	16,160	13,111	41,356	32,096
TOTAL	143,289	114,061	393,439	334,472
OPERATING EXPENSES				
Fuel for Electric Generation	41,907	29,380	100,491	75,498
Purchased Electricity for Resale	1,563	359	5,473	1,118
Purchased Electricity from AEP Affiliates	45,300	37,366	131,049	101,730
Other Operation	15,992	13,405	45,969	40,176
Maintenance	7,180	5,925	21,578	23,464
Depreciation and Amortization	11,318	11,004	33,695	32,768
Taxes Other Than Income Taxes	2,457	2,208	7,101	6,931
Income Taxes	3,212	935	7,499	8,489
TOTAL	128,929	100,582	352,855	290,174
OPERATING INCOME	14,360	13,479	40,584	44,298
Nonoperating Income	966	(137)	2,032	1,297
Nonoperating Expenses	89	168	401	1,755
Nonoperating Income Tax Expense (Credit)	283	(144)	492	(238)
Interest Charges	7,227	7,158	21,665	22,239
NET INCOME	$ 7,727	$ 6,160	$ 20,058	$ 21,839

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER 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	$ 50,450	$208,750	$ 64,151	$ (6,213)	$317,138
Common Stock Dividends			(16,000)		(16,000)
TOTAL					301,138
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $542				(1,005)	(1,005)
NET INCOME			21,839		21,839
TOTAL COMPREHENSIVE INCOME					20,834
SEPTEMBER 30, 2004	$ 50,450	$208,750	$ 69,990	$ (7,218)	$321,972
DECEMBER 31, 2004	$ 50,450	$208,750	$ 70,555	$ (8,775)	$320,980
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,534				(2,848)	(2,848)
NET INCOME			20,058		20,058
TOTAL COMPREHENSIVE INCOME					17,210
SEPTEMBER 30, 2005	$ 50,450	$208,750	$ 90,613	$ (11,623)	$338,190

See Condensed Notes to Financial Statements of Registrant Subsidiaries.