EMPIRE DISTRICT ELECTRIC COMPANY
ER-2006-0315
Data Request
of
Praxair, Inc. and Explorer Pipeline Company
to
Empire District Electric Company

ek

August 5, 2006

Item No.	Description
249.	Please provide a full and accurate copy of the 10Q filed on November 9, 2005.

FILED

SEP 2 9 2006

Missouri Public
Service Commission

Praxair Exhibit No. 124
Case No(s). ER-2006-0315
Date 9-12-06 Rptr KF

The attached or above information provided to the requesting party or parties in response to this data or information request is accurate and complete and contains no material misrepresentations or omissions, based upon present facts to the best of the knowledge, information or belief of the undersigned. The undersigned agrees to immediately inform the requesting party or parties if during the pendency of this case any matters are discovered which would materially affect the accuracy or completeness of the attached information and agrees to regard this as a continuing data request.

As used in this request the term "document" includes publications in any format, work papers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data recordings, transcriptions and printer, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to the party to whom this request is tendered and named above and includes its employees, contractors, agents or others employed by or acting in its behalf.

Signed: Debbie Gill

Date: 8-8-06

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

☒ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2005 or

☐ Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ____________ to ___________.

Commission file number: 1-3368

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Kansas (State of Incorporation)	44-0236370 (I.R.S. Employer Identification No.)
602 Joplin Street, Joplin, Missouri (Address of principal executive offices)	64801 (zip code)

Registrant's telephone number: (417) 625-5100

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes √ No ___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes √ No ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes___ No √

As of November 1, 2005, 26,030,457 shares of common stock were outstanding.

THE EMPIRE DISTRICT ELECTRIC COMPANY

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PART I. FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004
Operating revenues:		
Electric	$ 117,949,642	$ 91,089,046
Water	399,142	357,683
Non-regulated (Note 9)	6,596,395	5,294,802
	124,945,179	96,741,531
Operating revenue deductions:		
Fuel	36,754,447	17,615,547
Purchased power	12,210,374	11,834,945
Regulated – other (Note 8)	13,314,660	12,646,542
Non-regulated (Note 9)	6,287,090	5,362,415
Maintenance and repairs	4,664,958	4,682,946
Depreciation and amortization	9,255,782	7,756,286
Provision for income taxes	9,842,886	8,348,187
Other taxes	5,531,012	4,821,916
	97,861,209	73,068,784
Operating income	27,083,970	23,672,747
Other income and deductions:		
Allowance for equity funds used during construction	62,219	26,253
Interest income	66,876	27,751
Provision for other income taxes	13,427	37,845
Minority interest	(134,011)	(39,328)
Other non-operating expense	(301,411)	(198,960)
	(292,900)	(146,439)
Interest charges:		
Long-term debt – other	5,970,168	6,158,455
Note payable to securitization trust	1,062,500	1,062,500
Commercial paper	60,961	8,055
Allowance for borrowed funds used during construction	(62,801)	(22,803)
Other	166,605	85,003
	7,197,433	7,291,210
Net income	$ 19,593,637	$ 16,235,098
Weighted average number of common shares outstanding - basic	25,962,148	25,539,226
Weighted average number of common shares outstanding - diluted	26,014,545	25,585,988
Earnings per weighted average share of common stock - basic	$ 0.75	$ 0.64
Earnings per weighted average share of common stock - diluted	$ 0.75	$ 0.63
Dividends per share of common stock	$ 0.32	$ 0.32

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Operating revenues:		
Electric	$ 273,172,914	$ 234,236,973
Water	1,083,615	1,031,290
Non-regulated (Note 9)	18,115,124	16,007,652
	292,371,653	251,275,915
Operating revenue deductions:		
Fuel	84,592,388	52,536,158
Purchased power	36,037,328	38,324,825
Regulated – other (Note 8)	41,225,509	39,058,498
Non-regulated (Note 9)	18,146,706	16,356,216
Maintenance and repairs	15,161,508	15,926,967
Depreciation and amortization	26,329,174	22,949,839
Provision for income taxes	11,354,793	10,297,780
Other taxes	14,743,813	13,589,487
	247,591,219	209,039,770
Operating income	44,780,434	42,236,145
Other income and deductions:		
Allowance for equity funds used during construction	110,744	53,985
Interest income	170,320	56,953
Provision for other income taxes	69,988	147,237
Minority interest	(183,669)	(106,869)
Other non-operating income	-	67,016
Other non-operating expense	(721,129)	(663,497)
	(553,746)	(445,175)
Interest charges:		
Long-term debt – other	18,089,555	18,478,197
Note payable to securitization trust	3,187,500	3,187,500
Commercial paper	170,424	19,854
Allowance for borrowed funds used during construction	(149,641)	(59,012)
Other	426,789	273,605
	21,724,627	21,900,144
Net income	$ 22,502,061	$ 19,890,826
Weighted average number of common shares outstanding - basic	25,850,808	25,410,881
Weighted average number of common shares outstanding -diluted	25,900,485	25,460,967
Earnings per weighted average share of common stock -basic	$ 0.87	$ 0.78
Earnings per weighted average share of common stock -diluted	$ 0.87	$ 0.78
Dividends per share of common stock	$ 0.96	$ 0.96

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Twelve Months Ended September 30, 2005	Twelve Months Ended September 30, 2004
Operating revenues:		
Electric	$ 341,526,286	$ 301,113,693
Water	1,421,640	1,360,892
Non-regulated (Note 9)	23,687,447	21,768,539
	366,635,373	324,243,124
Operating revenue deductions:		
Fuel	96,496,773	62,681,018
Purchased power	50,558,121	51,734,636
Regulated – other (Note 8)	55,129,373	51,689,629
Non-regulated (Note 9)	24,763,072	21,800,826
Maintenance and repairs	20,028,171	21,084,010
Depreciation and amortization	34,177,189	30,327,376
Provision for income taxes	12,111,048	12,595,647
Other taxes	19,287,462	17,717,697
	312,551,209	269,630,839
Operating income	54,084,164	54,612,285
Other income and deductions:		
Allowance for equity funds used during construction	178,432	53,985
Interest income	318,546	72,324
Provision for other income taxes	(323,214)	300,567
Minority interest	231,306	(19,471)
Other non-operating income	-	77,006
Other non-operating expense	(1,026,729)	(913,345)
	(621,659)	(428,934)
Interest charges:		
Long-term debt – other	24,252,171	24,705,510
Note payable to securitization trust	4,250,000	3,187,500
Trust preferred distributions by subsidiary holding solely parent debentures	-	1,062,500
Commercial paper	170,424	159,795
Allowance for borrowed funds used during construction	(188,685)	(17,315)
Other	519,827	349,643
	29,003,737	29,447,633
Net income	$ 24,458,768	$ 24,735,718
Weighted average number of common shares outstanding - basic	25,796,938	24,858,904
Weighted average number of common shares outstanding -diluted	25,844,241	24,909,921
Earnings per weighted average share of common stock -basic	$ 0.95	$ 1.00
Earnings per weighted average share of common stock – diluted	$ 0.95	$ 0.99
Dividends per share of common stock	$ 1.28	$ 1.28

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended September 30,	
	2005	2004
Net income	$ **19,593,637**	$ 16,235,098
Reclassification adjustments for gains included in net income or reclassified to regulatory asset or liability	**(3,355,843)**	(3,980,080)
Change in fair market value of open derivative contracts for period	**15,572,183**	4,088,150
Income taxes	**(4,642,209)**	(41,066)
Net change in unrealized gain on derivative contracts	**7,574,131**	67,004
Comprehensive Income	$ **27,167,768**	$ 16,302,102

	Nine Months Ended September 30,	
	2005	2004
Net income	$ **22,502,061**	$ 19,890,826
Reclassification adjustments for gains included in net income or reclassified to regulatory asset or liability	**(2,222,158)**	(9,198,210)
Change in fair market value of open derivative contracts for period	**31,752,218**	7,673,380
Income taxes	**(11,221,423)**	579,436
Net change in unrealized gain on derivative contracts	**18,308,637**	(945,394)
Comprehensive Income	$ **40,810,698**	$ 18,945,432

	Twelve Months Ended September 30,	
	2005	2004
Net income	$ **24,458,768**	$ 24,735,718
Reclassification adjustments for gains included in net income or reclassified to regulatory asset or liability	**(4,494,968)**	(14,995,717)
Change in fair market value of open derivative contracts for period	**28,294,238**	12,928,864
Income taxes	**(9,043,723)**	785,404
Net change in unrealized gain on derivative contracts	**14,755,547**	(1,281,449)
Comprehensive Income	$ **39,214,315**	$ 23,454,269

See accompanying Notes to Consolidated Financial Statements

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEET (UNAUDITED)

	September 30, 2005	December 31, 2004
Assets		
Plant and property, at original cost:		
Electric	$1,252,390,772	$ 1,221,384,998
Water	9,675,908	9,201,314
Non-regulated	25,519,535	23,668,864
Construction work in progress	30,595,305	8,653,720
	1,318,181,520	1,262,908,896
Accumulated depreciation and amortization	428,976,212	405,873,917
	889,205,308	857,034,979
Current assets:		
Cash and cash equivalents	10,267,653	12,593,369
Accounts receivable - trade, net	38,283,587	20,052,892
Accrued unbilled revenues	7,242,624	7,599,964
Accounts receivable – other (Note 7)	8,591,992	12,874,123
Fuel, materials and supplies	29,461,292	32,044,113
Unrealized gain in fair value of derivative contracts (Note 3)	10,175,990	2,867,550
Prepaid expenses	3,019,605	1,952,236
	107,042,743	89,984,247
Noncurrent assets and deferred charges:		
Regulatory assets (Note 6)	54,676,001	52,127,262
Unamortized debt issuance costs	5,815,201	5,881,384
Unrealized gain in fair value of derivative contracts (Note 3)	25,679,650	4,142,900
Prepaid pension asset	9,243,589	13,973,827
Other	4,697,808	4,393,939
	100,112,249	80,519,312
Total Assets	$1,096,360,300	$1,027,538,538

(Continued)

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEET (UNAUDITED)

	September 30, 2005	December 31, 2004
Capitalization and Liabilities		
Common stock, $1 par value, 26,009,678 and 25,695,972 shares issued and outstanding, respectively	$ 26,009,678	$ 25,695,972
Capital in excess of par value	327,861,816	321,632,092
Retained earnings	26,757,366	29,078,105
Accumulated other comprehensive income, net of income tax (Note 3)	21,082,858	2,774,221
Total common stockholders' equity	401,711,718	379,180,390
Long-term debt:		
Note payable to securitization trust	50,000,000	50,000,000
Obligations under capital lease	-	122,570
First mortgage bonds and secured debt	110,097,708	140,363,500
Unsecured debt	249,211,501	209,430,556
Total long-term debt	409,309,209	399,916,626
Total long-term debt and common stockholders' equity	811,020,927	779,097,016
Current liabilities:		
Accounts payable and accrued liabilities	46,113,432	36,926,520
Current maturities of long-term debt	497,988	10,462,211
Obligations under capital lease	223,699	239,684
Customer deposits	6,130,116	5,724,211
Interest accrued	6,866,503	2,700,402
Unrealized loss in fair value of derivative contracts (Note 3)	2,119,400	1,030,100
Taxes accrued	16,339,058	1,411,355
Other current liabilities	3,437,408	708,643
	81,727,604	59,203,126
Commitments, contingencies and benefits (Note 5)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities (Note 6)	31,509,715	30,225,020
Deferred income taxes	143,990,889	132,694,686
Unamortized investment tax credits	4,599,768	5,041,000
Postretirement benefits other than pensions	7,615,971	8,248,004
Unrealized loss in fair value of derivative contracts (Note 3)	1,026,200	1,505,800
Minority interest	854,515	705,326
Other	14,014,711	10,818,560
	203,611,769	189,238,396
Total Capitalization and Liabilities	$1,096,360,300	$1,027,538,538

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Operating activities:		
Net income	$ 22,502,061	$ 19,890,826
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation and amortization	29,700,497	26,381,028
Pension costs	4,808,908	2,254,161
Deferred income taxes, net	1,445,539	7,672,530
Investment tax credit, net	(441,232)	(426,065)
Allowance for equity funds used during construction	(110,744)	(53,985)
Issuance of common stock and stock options for incentive plans	1,396,646	1,819,550
(Gain)/loss on derivatives	1,294,570	(98,770)
Cash flows impacted by changes in:		
Accounts receivable and accrued unbilled revenues	(13,591,224)	(5,223,429)
Fuel, materials and supplies	2,582,821	(683,932)
Prepaid expenses and deferred charges	(2,341,625)	(604,759)
Accounts payable and accrued liabilities	17,122,575	275,351
Customer deposits, interest and taxes accrued	19,499,709	12,340,573
Other liabilities and other deferred credits	2,721,117	1,586,076
Net cash provided by operating activities	86,589,618	65,129,155
Investing activities:		
Capital expenditures – regulated	(55,560,978)	(27,937,042)
Capital expenditures and other investments- non-regulated	(1,994,815)	(2,271,715)
Net cash used in investing activities	(57,555,793)	(30,208,757)
Financing activities:		
Payment of interest rate derivative	(1,385,935)	-
Proceeds from issuance of senior notes	40,000,000	-
Proceeds from issuance of common stock	5,146,784	11,389,589
Long-term debt issuance costs	(533,949)	-
Premium paid on extinguished debt	(1,162,500)	-
Discount on issuance of senior notes	(220,000)	-
Redemption of first mortgage bonds	(40,000,000)	-
Net (repayments) proceeds from short-term borrowings	(7,935,662)	(22,037,445)
Dividends	(24,822,800)	(24,410,247)
Net (repayments) proceeds from non-regulated notes payable	(301,925)	(219,917)
Other	(143,554)	(109,989)
Net cash used in financing activities	(31,359,541)	(35,388,009)
Net decrease in cash and cash equivalents	(2,325,716)	(467,611)
Cash and cash equivalents at beginning of period	12,593,369	13,108,197
Cash and cash equivalents at end of period	$ 10,267,653	$ 12,640,586

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 - Summary of Significant Accounting Policies

The accompanying interim financial statements do not include all disclosures included in the annual financial statements and therefore should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

The information furnished reflects all adjustments, consisting only of normal recurring adjustments, which are in our opinion necessary to present fairly the results for the interim periods as well as present these periods on a consistent basis with the financial statements for the fiscal year ended December 31, 2004. Certain reclassifications have been made to prior year information to conform to the current year presentation.

Note 2 - Recently Issued Accounting Standards

On March 30, 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). FIN 47 clarifies that an entity must record a liability for a "conditional" asset retirement obligation if the fair value of the obligation can be reasonably estimated. It also clarifies the FASB's views on when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for us no later than December 31, 2005. We are in the process of evaluating the impact of this new interpretation. It will likely require the accrual of additional liabilities and could result in increased expense if the costs associated with these additional liabilities are not recovered in electric rates. However, the amount of any additional liabilities has not yet been determined.

In December 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004) "Share-Based Payments" (FAS 123(R)). The statement requires companies to record stock compensation expense in their financial statements based on a fair value methodology beginning no later than the first fiscal quarter beginning after June 15, 2005. During 2002, we adopted FAS 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an Amendment of SFAS 123" (FAS 148) and elected to adopt the accounting provisions of FAS 123 "Accounting for Stock-Based Compensation" (FAS 123). Under FAS 123, we currently recognize compensation expense over the vesting period of all stock-based compensation awards issued subsequent to January 1, 2002 based upon the fair-value of the award as of the date of issuance. On April 14, 2005, the SEC approved a new rule for public companies that delays the effective date of FAS 123(R), giving a number of those companies more time to develop their implementation strategies. Except for this deferral of the effective date, the guidance in FAS 123(R) is unchanged. FAS 123(R) will now be effective for us on January 1, 2006. We do not expect the adoption of this standard to have a material impact on our financial statements.

In December 2004, the FASB issued SFAS No. 153 (FAS 153) "Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29", effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005, and therefore effective for us on July 1, 2005. FAS No. 153 requires that exchanges of productive assets be accounted for at fair value unless fair value cannot be reasonably determined or the transaction lacks commercial substance. FAS No. 153 has not had and is not expected to have a material effect on our consolidated financial statements.

In December 2004, the FASB issued Staff Position 109-1, "Application on FASB Statement No. 109, Accounting for Income Taxes for the Tax Deduction Provided to U.S. Based Manufacturers by the American Jobs Creation Act of 2004" (FSP 109-1). FSP 109-1 clarifies how to apply Statement No. 109 to the new law's tax deduction for income attributable to "Domestic production activities." An estimate of the impact of this law is reflected in our current year tax provision. The effect of this estimate is not material to the total provision for income taxes or the financial statements as a whole.

See Note 1 under "Notes to Consolidated Financial Statements" in our Annual Report on Form 10-K for the year ended December 31, 2004 for further information regarding recently issued accounting standards.

Note 3 - Risk Management and Derivative Financial Instruments

We utilize derivatives to manage our natural gas commodity market risk to help manage our exposure resulting from purchasing natural gas, to be used as fuel, on the volatile spot market and to manage certain interest rate exposure.

We have recorded the following assets and liabilities (in thousands) representing the fair value of qualifying derivative financial instruments held as of September 30, 2005 and December 31, 2004 and subject to the reporting requirements of FAS 133:

	September 30, 2005	December 31, 2004
Current assets	$ 10,176	$ 2,868
Noncurrent assets	25,680	4,143
Current liabilities	2,119	1,030
Noncurrent liabilities	1,026	1,506

A $21.1 million, net of tax, net unrealized gain representing the fair market value of the effective position of these contracts is recognized as Accumulated Other Comprehensive Income in the capitalization section of the balance sheet. The total tax effect of $12.9 million on this gain is recorded in deferred taxes. These amounts will be adjusted cumulatively on a monthly basis during the determination periods beginning October 1, 2005 and ending on September 30, 2013. At the end of each determination period, any previously unrealized gain or loss for that period related to the instrument will be reclassified to fuel expense.

We record unrealized gains/(losses) on the overhedged portion of our gas hedging activities, if any, in "Fuel" under the Operating Revenue Deductions section of our income statements since all of our gas hedging activities are related to stabilizing fuel costs as part of our fuel procurement program and are not speculative activities.

The following table sets forth "mark-to-market" pre-tax gains/(losses) from our hedging activities included in "Fuel" (in thousands) for each of the periods ended September 30:

	Three Months Ended		Nine Months Ended		Twelve Months Ended	
	2005	2004	2005	2004	2005	2004
Overhedged Portion	$ (1,324)	$ (337)	$ (820)	$ (377)	$ 262	$ (453)
Qualified Portion	$ 3,356	$3,980	$ 3,608	$9,198	$5,881	$9,896

As of October 28, 2005, 69.9% of our anticipated volume of natural gas usage for November and December of 2005 is hedged (either through derivative contracts or physical purchase agreements) at an average price of $6.33 per Dekatherm (Dth). In addition, the following percentages and amounts, in Dths, of our anticipated volume of natural gas usage for the next eight years are hedged at the following average prices per Dth:

Year	% Hedged	Dth Hedged	Average Price
2006	74%	5,699,986	$6.018
2007	49%	4,800,000	$5.398
2008	29%	3,000,000	$5.660
2009-2013	27%	13,488,000	$5.755

In September 2005, we unwound part of a physical purchase of natural gas for the 2009 through 2011 period as part of our fuel management process, which resulted in a $5 million one-time gain. This gain was recognized in the current quarter as a decrease to fuel expense.

See Note 4 – Long-Term Debt and Short-Term Borrowings (below) for information on our hedging of interest rates.

Note 4 – Long-Term Debt and Short-Term Borrowings

On April 1, 2005, we redeemed our $10 million First Mortgage Bonds, 7.60% Series due April 1, 2005, using short-term debt. On June 27, 2005, we issued $40 million aggregate principal amount of our Senior Notes, 5.8% Series due 2035 (2035 Notes), for net proceeds of approximately $39.4 million less $0.1 million of legal fees. We used the net proceeds from this issuance to redeem all $30 million aggregate principal amount of our First Mortgage Bonds, 7.75% Series due 2025 for approximately $31.3 million, including interest and a redemption premium, and to repay short-term debt. The $1.2 million redemption premium paid in connection with the redemption of these first mortgage bonds, together with $2.4 million of remaining unamortized loss on reacquired debt and $0.3 million of unamortized debt expense, were recorded as a regulatory asset and are being amortized as interest expense over the life of the 2035 Notes. We had entered into an interest rate derivative contract in May 2005 to hedge against the risk of a rise in interest rates impacting the 2035 Notes prior to their issuance. Costs associated with the interest rate derivative (primarily due to interest rate fluctuations) amounted to approximately $1.4 million and were recorded as a regulatory asset and are being amortized over the life of the 2035 Notes.

On July 15, 2005, we entered into a $150 million five year unsecured credit agreement with UMB Bank, N.A., as administrative agent, Bank of America, N.A., as syndication agent, and the other lenders party thereto. This agreement replaced our pre-existing $100 million unsecured credit agreement, which was terminated upon entering into the new agreement. The credit agreement provides for $150 million of revolving loans to be available for working capital, general corporate purposes and to back-up our use of commercial paper. Interest on borrowings under the credit agreement accrues at a rate equal to, at our option, (i) the bank's prime commercial rate plus a margin or (ii) LIBOR plus a margin, in each case based on our then current credit ratings. This agreement requires our total indebtedness (which does not include our note payable to the securitization trust) to be less than 62.5% of our total capitalization at the end of each fiscal quarter and our EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to be at least two times our interest charges (which includes interest on the note payable to the securitization trust) for the trailing four fiscal quarters at the end of each fiscal quarter. Failure to maintain these ratios will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. We are in compliance with these ratios as of September 30, 2005. This credit agreement is also subject to cross-default if we default on in excess of $10 million in the aggregate on our other indebtedness. There were no outstanding borrowings under this agreement at September 30, 2005.

Note 5 – Commitments, Contingencies and Benefits

Pension and Other Employment and Post -Employment Benefits

Based on the performance of our pension plan assets through January 1, 2004 and January 1, 2005, we were not required under the Employee Retirement Income Security Act of 1974 (ERISA) to fund any additional minimum ERISA amounts with respect to 2004 or 2005. Given recent market returns, however, we could face a position at December 31, 2005 where our accumulated pension benefit obligation exceeds the fair value of our plan assets. If this situation exists, we may elect to make an additional cash contribution to our pension plan. The amount of the liability, or cash contribution, if any, will depend upon asset returns experienced in the remainder of 2005. There would be no effect to net income if this liability is recognized or if a cash contribution is made.

We expect to make Other Post-Employment Benefits (OPEB) contributions of $5.8 million in 2005, of which $4.4 million has been made as of September 30, 2005.

The components of our net periodic cost of pension (expensed and capitalized) and other post-employment benefits (in thousands) are summarized below:

	Pension Benefits		**OPEB**	
	Three months ended September 30			
	2005	2004	2005	2004
Service cost	$ 705	$ 599	$ 503	$ 640
Interest cost	1,357	1,575	616	575
Expected return on plan assets	(1,563)	(1,860)	(635)	(435)
Amortization of prior service cost	100	163	(172)	(152)
Amortization of transition obligation	-	-	290	271
Amortization of net loss	681	298	338	244
Net periodic benefit cost	$1,280	$ 775	$ 940	$1,143

	Pension Benefits		**OPEB**	
	Nine months ended September 30			
	2005	2004	2005	2004
Service cost	$2,455	$2,083	$1,603	$1,138
Interest cost	4,807	4,646	2,566	2,243
Expected return on plan assets	(5,413)	(5,591)	(1,835)	(1,469)
Amortization of prior service cost	350	441	(472)	(457)
Amortization of transition obligation	-	-	840	813
Amortization of net loss	2,531	675	1,488	1,307
Net periodic benefit cost	$4,730	$2,254	$4,190	$3,575

	Pension Benefits		**OPEB**	
	Twelve months ended September 30			
	2005	2004	2005	2004
Service cost	$3,130	$2,720	$1,983	$1,409
Interest cost	6,307	6,118	3,313	3,094
Expected return on plan assets	(7,277)	(7,197)	(2,325)	(1,872)
Amortization of prior service cost	465	581	(624)	(457)
Amortization of transition obligation	-	-	1,111	1,084
Amortization of net loss	2,752	997	1,924	1,703
Net periodic benefit cost	$5,377	$3,219	$5,382	$4,961

We began recording a regulatory asset for deferred pension costs during the second quarter of 2005 per our March 10, 2005 Missouri rate case order. As of September 30, 2005, the deferral is approximately $1.0 million, which we expect to collect in rates in future periods.

Stock Compensation

We recognize compensation expense over the vesting period of stock-based compensation awards based upon the fair-value of the award as of the date of issuance. There were 24,200 stock awards granted in the first nine months of 2005, all of which were granted in the first quarter, relating to the performance-based restricted stock award portion of our stock incentive plan. The fair value of these awards is equal to the market price of Empire common stock on the date of grant, which will be recorded as expense over the vesting period.

We also utilize stock options as part of our employee compensation plan. The following table summarizes the activity of the stock option portion of our stock incentive plan for the first nine months of 2005.

	Options	Weighted Average Exercise Price
Outstanding, January 1, 2005	173,100	$20.45
Granted	39,100	$22.77
Exercised	69,700	$20.95
Forfeited	-	-
Outstanding, September 30, 2005	142,500	$20.84
Exercisable, September 30, 2005	-	-

In addition, we issued 9,243 common shares in the third quarter of 2005 relating to our 401(k) Plan matching contributions.

We recognized the following amounts (in thousands) in compensation expense for all of our stock-based compensation plans, as well as our employee stock purchase plan, for the periods listed.

	September 30, 2005	September 30, 2004
Third Quarter	$ 405	$ 501
Nine Months Ended	1,268	1,743
Twelve Months Ended	1,751	2,004

Note 6 – Regulatory Matters

All of our regulatory assets as of September 30, 2005 have been allowed recovery in the state of Missouri as a result of the March 10, 2005 rate case order, except for $2.2 million which primarily consists of a realized loss associated with an interest rate derivative of $1.4 million. All of these costs were incurred subsequent to this rate order (see "Note 4 – Long-Term Debt and Short-Term Borrowings" for additional information). We expect our regulatory assets related to premiums and related costs for reacquisitions and issuance of debt and those related to post-employment benefit cost incurred since our latest rate cases in the other jurisdictions to also be allowed recovery since these items have historically been allowed in our rate cases. In addition, losses and gains on our prior interest rate derivatives were included in our recently approved Missouri rate case. Since these items increase and reduce, respectively, our effective interest cost, we believe it is probable they will also be allowed in our other jurisdictions, as well. At September 30, 2005, our regulatory assets totaled $54.7 million.

We are currently collecting an Interim Energy Charge (IEC) of $0.002131 per kilowatt hour of customer usage authorized by the Missouri Public Service Commission (MPSC). This IEC "collar" is designed to recover variable fuel and purchased power costs we incur subject to a ceiling (and floor) on the amount recoverable (including realized gains or losses associated with our natural gas hedging program discussed in Note 3) which are higher than such costs included in the base rates allowed in the most recent Missouri rate case. This revenue is recorded when service is provided to the customer and subject to refund to the extent collected amounts exceed variable fuel and purchased power costs. At each balance sheet date, we evaluate the probability that we would be required to refund either a portion or all of the amounts collected under the IEC to ratepayers. At September 30, 2005, no provision for refund has been recorded.

Note 7 – Accounts Receivable - Other

The following table sets forth the major components comprising "Accounts receivable – other" on our consolidated balance sheet (in thousands):

	September 30, 2005	December 31, 2004
Accounts receivable for meter loops, meter bases, line extensions, highway projects, etc.	$ 1,237	$ 1,890
Accounts receivable for insurance reimbursement for Energy Center (1)	-	1,941
Accounts receivable for non-regulated subsidiary companies	3,225	3,062
Accounts receivable from Westar Generating, Inc. for commonly-owned facility	577	544
Taxes receivable – overpayment of estimated income taxes	9	4,151
Accounts receivable for true-up on maintenance contracts (2)	1,658	1,199
Accounts receivable – energy trading margin deposit (3)	1,841	-
Other	45	87
Total accounts receivable – other	$ 8,592	$ 12,874

(1) The decrease of $1.9 million accounts receivable for insurance reimbursement for Energy Center at September 30, 2005 relates to $4.1 million of total expenses for repairs to our Unit No. 2 combustion turbine at the Energy Center, less our $1.0 million deductible which was expensed in the first quarter of 2004 and $3.1 million of insurance reimbursement received as of September 30, 2005 (of which $1.1 million had been received as of December 31, 2004).

(2) The $1.7 million in accounts receivable for true-up on maintenance contracts represents $1.1 million remaining of the $2.6 million gross amount of a true-up credit from Siemens Westinghouse in September 2005 related to our maintenance contract entered into in July 2001 for the State Line Combined Cycle Unit (SLCC) and $0.6 million of quarterly estimated credits accrued in the third quarter of 2005. The measurement period for this maintenance contract runs from June 1, 2005 through May 31, 2006. Forty percent of this credit belongs to Westar Generating, Inc., the owner of 40% of the SLCC, and has been recorded in accounts payable as of September 30, 2005.

(3) The $1.8 million in accounts receivable for energy trading margin deposit represents the balance in our brokerage account as of September 30, 2005. NYMEX futures contracts are used in our natural gas hedging program which requires posting of margin.

Note 8 - Regulated - Other Operating Expense

The following table sets forth the major components comprising "Regulated – other" under "Operating Revenue Deductions" on our consolidated statements of operations (in thousands) for all periods presented ended September 30:

	3 Months Ended	3 Months Ended	9 Months Ended	9 Months Ended	12 Months Ended	12 Months Ended
	2005	2004	2005	2004	2005	2004
Transmission and distribution expense	$ 2,305	$ 1,796	$ 6,128	$ 5,542	$ 8,027	$ 7,480
Power operation expense (other than fuel)	2,478	2,514	6,900	7,492	9,391	9,760
Customer accounts & assistance expense	1,759	1,725	5,196	5,189	7,106	6,981
Employee pension expense	824	703	3,291	2,068	4,242	2,922
Employee healthcare plan	1,760	1,824	6,851	5,594	9,256	7,400
General office supplies and expense	1,705	1,840	4,909	5,399	7,201	7,060
Administrative and general expense	2,079	2,015	6,538	6,464	8,226	8,433
Allowance for uncollectible accounts	416	227	1,344	1,230	1,570	1,556
Miscellaneous expense	(11)	3	69	80	110	98
Total	$ 13,315	$ 12,647	$ 41,226	$ 39,058	$ 55,129	$ 51,690

Note 9 - Non-regulated Businesses

The table below presents information (in thousands) about the reported revenues, operating income, net income, capital expenditures, total assets and minority interests of our non-regulated businesses.

	For the quarter ended September 30,			
	2005		2004	
	Non-Regulated	Total Company	Non-Regulated	Total Company
Statement of Income Information				
Revenues	$ 6,728*	$ 124,945	$ 5,384*	$ 96,742
Operating income (loss)	$ (59)	$ 27,084	$ (286)	$ 23,673
Net income (loss)	$ (217)	$ 19,594	$ (372)	$ 16,235
Minority interest	$ (134)	$ (134)	$ (39)	$ (39)
Capital Expenditures				
	$ 516	$ 15,255	$ 622	$ 10,329

	As of September 30, 2005		As of December 31, 2004	
	Non-Regulated	Total Company	Non-Regulated	Total Company
Balance Sheet Information				
Total assets	$ 27,094	$ 1,096,360	$ 25,296	$ 1,027,539
Minority interest	$ (855)	$ (855)	$ (705)	$ (705)

	For the nine-months-ended September 30,			
	2005		2004	
	Non-Regulated	Total Company	Non-Regulated	Total Company
Statement of Income Information				
Revenues	$ 18,404*	$ 292,372	$ 16,259*	$ 251,276
Operating income (loss)	$ (765)	$ 44,780	$ (888)	$ 42,236
Net income (loss)	$ (1,100)	$ 22,502	$ (1,143)	$ 19,891
Minority interest	$ (184)	$ (184)	$ (107)	$ (107)
Capital Expenditures				
	$ 1,995	$ 57,556	$ 2,272	$ 30,209

	For the twelve-months-ended September 30,							
	2005				2004			
	Non-Regulated		Total Company		Non-Regulated		Total Company	
Statement of Income Information								
Revenues	$	24,080*	$	366,635	$	22,128*	$	324,243
Operating income (loss)	$	(1,636)	$	54,084	$	(1,019)	$	54,612
Net income (loss)	$	(1,790)	$	24,459	$	(1,113)	$	24,736
Minority interest	$	231	$	231	$	(19)	$	(19)
Capital Expenditures								
	$	2,423	$	54,143	$	2,863	$	40,378

**Includes revenues received from the regulated business that are eliminated in consolidation.*

FORWARD LOOKING STATEMENTS

Certain matters discussed in this quarterly report are "forward-looking statements" intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Such statements address or may address future plans, objectives, expectations and events or conditions concerning various matters such as capital expenditures, earnings, pension and other costs, competition, litigation, our construction program, our generation plans, our financing plans, potential acquisitions, rate and other regulatory matters, liquidity and capital resources and accounting matters. Forward-looking statements may contain words like "anticipate," "believe," "expect," "project," "objective" or similar expressions to identify them as forward-looking statements. Factors that could cause actual results to differ materially from those currently anticipated in such statements include:

- the amount, terms and timing of rate relief we seek and related matters;
- the cost and availability of purchased power and fuel, and the results of our activities (such as hedging) to reduce the volatility of such costs;
- electric utility restructuring, including ongoing state and federal activities;
- weather, business and economic conditions and other factors which may impact customer growth;
- operation of our generation facilities;
- legislation;
- regulation, including environmental regulation (such as NOx regulation);
- competition;
- the impact of deregulation on off-system sales;
- changes in accounting requirements;
- other circumstances affecting anticipated rates, revenues and costs, including pension and post-retirement costs;
- the timing of, and integration costs relating to, contemplated acquisitions and the performance of acquired businesses;
- matters such as the effect of changes in credit ratings on the availability and our cost of funds;
- the periodic revision of our construction and capital expenditure plans and cost estimates;
- the performance and liquidity needs of our non-regulated businesses;
- the success of efforts to invest in and develop new opportunities; and
- costs and effects of legal and administrative proceedings, settlements, investigations and claims.

All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and may be beyond our control. New factors emerge from time to time and it is not possible for management to predict all such factors or to assess the impact of each such factor on us. Any forward-looking statement speaks only as of the date on which such statement is made, and we do not undertake any obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made.

We caution you that any forward-looking statements are not guarantees of future performance and involve known and unknown risk, uncertainties and other factors which may cause our actual results, performance or achievements to differ materially from the facts, results, performance or achievements we have anticipated in such forward-looking statements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

EXECUTIVE SUMMARY

The Empire District Electric Company is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. We also provide water service to three towns in Missouri and have investments in certain non-regulated businesses including fiber optics, Internet access, close-tolerance custom manufacturing and customer information system software services through our wholly owned subsidiary, EDE Holdings, Inc. In 2004, 93.0% of our gross operating revenues were provided from the sale of electricity, 0.4% from the sale of water and 6.6% from our non-regulated businesses. There were no significant changes in these percentages for the third quarter of 2005.

The primary drivers of our electric operating revenues in any period are: (1) weather, (2) rates we can charge our customers, (3) customer growth and (4) general economic conditions. Weather affects the demand for electricity for our regulated business. Very hot summers and very cold winters increase demand, while mild weather reduces demand. Residential and commercial sales are impacted more by weather than industrial sales, which are mostly affected by business needs for electricity and general economic conditions. The utility commissions in the states in which we operate, as well as the FERC, set the rates at which we can charge our customers. In order to offset expenses, we depend on our ability to receive adequate and timely recovery of our costs (primarily fuel and purchased power) and/or rate relief. We continue to assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary. Customer growth, which is the growth in the number of customers, contributes to the demand for electricity. We expect our annual customer growth to range from approximately 1.6% to 1.8% over the next several years, although our customer growth for the twelve months ended September 30, 2005 was 1.97%. We define sales growth to be growth in kWh sales excluding the impact of weather. The primary drivers of sales growth are customer growth and general economic conditions.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expense, (2) maintenance and repairs expense, (3) employee pension and health care costs, (4) taxes and (5) non-cash items such as depreciation and amortization expense. Fuel and purchased power costs are our largest expense items. Several factors affect these costs, including fuel and purchased power prices, plant outages and weather, which drives customer demand. In order to control the price we pay for fuel and purchased power, we have entered into long and short-term agreements to purchase coal and natural gas for our energy supply, have entered into a 20-year contract with PPM Energy to purchase approximately 550,000 megawatt-hours of energy, or 10% of our annual needs, from the Elk River Windfarm project beginning in December 2005, (we began receiving test energy in October 2005) and currently engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expense and improve predictability. Our recent Missouri rate case order also contained factors to help mitigate the above costs, including an IEC, designed to recover variable fuel and purchased power costs we incur which are higher than such costs included in the base rates allowed in our rate case. The order also contained a change in the recognition of pension costs, allowing us to defer the Missouri portion of any costs above the amount included in our rate case as a regulatory asset. In addition, the Arkansas Public Service Commission (APSC) allowed us to adjust our annual Energy Cost Recovery (ECR) rate midway through the regulatory year due to higher gas prices with the adjusted interim rate effective October 1, 2005 through March 31, 2006.

During the third quarter of 2005, basic earnings per weighted average share of common stock increased to \$0.75 as compared to \$0.64 in the third quarter of 2004 while diluted earnings per weighted average share of common stock were \$0.75 as compared to \$0.63 in the third quarter of 2004. For the nine months ended September 30, 2005, basic and diluted earnings per weighted average share of common stock increased to \$0.87 as compared to \$0.78 for the nine months ended September 30, 2004. For the twelve months ended September 30, 2005, basic earnings per weighted average share of common stock were \$0.95 as compared to \$1.00 for the twelve months ended September 30, 2004 while diluted earnings per weighted average share of common stock were \$0.95 as compared to \$0.99 for the twelve months ended September 30, 2004. As reflected in the table below, the primary negative driver for all periods ended September 30, 2005 was greater fuel costs, while the primary positive driver for all periods ended September 30, 2005 was increased revenues.

We expect the unprecedented high natural gas prices to continue to negatively impact our fuel and purchased power expenses in the near future. Given our limited ability to recover these added costs, we plan to file a Missouri rate case early in the first quarter of 2006 to request transition from the IEC to Missouri's new fuel adjustment mechanism. At this time, we cannot predict the outcome of this planned rate case filing.

The following reconciliation of basic earnings per share between the three months, nine months and twelve months ended September 30, 2004 versus September 30, 2005 is a non-GAAP presentation. We believe this information is useful in understanding the fluctuation in earnings per share between the prior and current year periods. The reconciliation presents the after tax impact of significant items and components of the statement of operations on a per share basis before the impact of additional stock issuances which is presented separately. Earnings per share for the three months, nine months and twelve months ended September 30, 2005 and 2004 shown in the reconciliation are presented on a GAAP basis and are the same as the amounts included in the statements of operations. This reconciliation may not be comparable to other companies or more useful than the GAAP presentation included in the statements of operations.

	Three Months Ended	Nine Months Ended	Twelve Months Ended
Earnings Per Share – 2004	**$ 0.64**	**$ 0.78**	**$ 1.00**
Revenues			
Electric	$ 0.70	$ 1.01	$ 1.09
Non – Regulated	0.03	0.06	0.05
Expenses			
Fuel and purchased power	(0.51)	(0.78)	(0.88)
Regulated – other (employee health care and pension expense)	0.00	(0.06)	(0.08)
Regulated – other (all other)	(0.02)	0.01	(0.01)
Non – Regulated	(0.02)	(0.05)	(0.08)
Maintenance and repairs	0.00	0.02	0.03
Depreciation and amortization	(0.04)	(0.09)	(0.10)
Other taxes	(0.02)	(0.03)	(0.04)
Interest charges	0.00	0.01	0.01
Other income and deductions	0.00	0.00	0.00
Dilutive effect of additional shares	(0.01)	(0.01)	(0.04)
Earnings Per Share – 2005	**$ 0.75**	**$ 0.87**	**$ 0.95**

Third Quarter Activities

On September 21, 2005, we announced that we had entered into an Asset Purchase Agreement with Aquila, Inc., pursuant to which we agreed to acquire the Missouri natural gas distribution operations of Aquila, Inc. (Missouri Gas). The Missouri Gas properties consist of approximately 48,500 customers in 44 Missouri communities in northwest, north central and west central Missouri. The base purchase price is $84 million in cash, plus working capital and subject to net plant adjustments. This transaction is subject to the approval of the Missouri Public Service Commission (MPSC) and other customary closing conditions. We filed an application with the MPSC on November 8, 2005 seeking approval and anticipate closing the transaction in mid 2006.

The MPSC final order issued on March 10, 2005 approved an annual increase in base rates for our Missouri electric customers of approximately $25.7 million, or 9.96%, and also approved an annual IEC of approximately $8.2 million effective March 27, 2005 and expiring three years later. From inception of the IEC through September 30, 2005, we incurred $7.0 million of fuel and purchased power costs in excess of the total cost set in our base rates and the IEC recorded during this period. For additional information regarding the IEC, see "-Results of Operations – Electric Operating Revenues and Kilowatt-Hour Sales - Rate Matters" below.

On April 29, 2005, we filed a request with the Kansas Corporation Commission (KCC) for an increase in base rates for our Kansas electric customers in the amount of $4,181,078, or 24.64%. On October 4, 2005, we and the KCC Staff filed a Stipulated Settlement Agreement (Agreement) with the KCC. The Agreement calls for an annual increase in rates for our Kansas electric customers of approximately $2.15 million and the implementation of an Energy Cost Adjustment Clause (ECA), a fuel rider that will collect fuel costs in the future. For additional information, see "-Results of Operations – Electric Operating Revenues and Kilowatt-Hour Sales - Rate Matters" below.

On February 4, 2005, we filed an application with the MPSC seeking approval of an Experimental Regulatory Plan (Plan) concerning our possible participation in a new 800-850 MW coal-fired unit (Iatan 2) to be operated by Kansas City Power & Light Company (KCP&L) and located at the site of the existing Iatan Generating Station (Iatan 1) near Weston, Missouri, or other baseload generation options. Our application also sought a certificate of convenience and necessity to participate in Iatan 2, if necessary, and in connection therewith, obtain approval that is intended to provide adequate assurance to potential investors to make financial options available to us concerning this. On July 18, 2005, we filed a Stipulation and Agreement (Agreement) regarding our Plan with the MPSC for its consideration and approval conditioned upon our participation in Iatan 2. The Agreement contains conditions related to our infrastructure investments, including Iatan 2, environmental investments in Iatan 1, our 155 MW V84.3A2 combustion turbine at our Riverton plant and installing Selective Catalytic Reduction (SCR) equipment at the Asbury coal-fired plant. The other parties to the Agreement include the Missouri Department of Natural Resources, the MPSC Staff, two of our industrial customers and the Office of the Public Counsel. The MPSC issued an order on August 2, 2005 approving the Agreement with an effective date of August 12, 2005.

In relation to the above Plan, we entered into a letter of intent with KCP&L on June 10, 2005 with respect to our potential purchase of an undivided ownership interest in Iatan 2. The estimated construction budget for Iatan 2 is approximately $1.26 billion with our first major expenditures planned in 2007 and 2008. The letter of intent relates to an allocation of at least 100 MW of generation capacity (and a proportionate share of the construction, operation and maintenance costs) to us. The letter of intent, insofar as it relates to Iatan 2, is not binding on the parties. The letter of intent also contains a clarification as to our obligations with respect to environmental upgrades at Iatan 1 and an agreement to reallocate certain interests in common facilities at Iatan 1 to the owners of Iatan 2. Empire currently owns a 12% interest in Iatan 1.

At September 30, 2005, the construction at our Riverton plant is on schedule for the installation of our new Siemens V84.3A2 combustion turbine, with a summer rated capacity of 155 megawatts, scheduled to be operational in 2007. On December 10, 2004, we entered into a 20-year contract with PPM Energy, to purchase the energy generated at the proposed Elk River Windfarm to be located in Butler County, Kansas. Construction of the windfarm began in May 2005 and we began receiving test energy in October 2005. We expect that the amount and percentage of electricity we generate by natural gas will decrease in 2006 and in the immediate future thereafter due to this contract. We anticipate purchasing approximately 550,000 megawatt-hours of energy, or 10% of our annual needs, from the project beginning in December 2005. We anticipate the cost of this contract to also be offset by purchasing less higher-priced power from other suppliers or by displacing on-system generation.

Several of the nation's utilities are experiencing decreased coal inventory levels due to railroad transportation problems delivering Wyoming coal. We also are experiencing a declining inventory situation. As of September 30, 2005, we had over 30 days of Western coal inventory at our Riverton plant and approximately 50 days of Western coal inventory at our Asbury plant, compared to over 70 days and approximately 75 days, respectively, as of June 30, 2005. Due to recent railroad congestion problems affecting delivery cycle times, we will remain in a declining inventory situation until a change in circumstances occurs. We leased a train on an interim basis, which slowed the rate of decline. Similar issues, such as slow cycle times, have also affected Iatan. We have implemented coal conservation measures at both Asbury and Riverton, including increased use of local coals not dependant upon railroad transportation. We have begun coal conservation measures at Iatan which we expect will have an estimated $1 million negative impact on our earnings in November and December of 2005. We cannot predict if these measures will still be necessary in the first quarter of 2006. Also, power deliveries under our Jeffery purchase power contract with Westar Energy were reduced for a period due to coal conservation efforts by Westar. This coal transportation situation and our coal conservation and supply replacement measures could have an adverse effect on our fuel and purchased power costs in future periods.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the three-month, nine-month and twelve-month periods ended September 30, 2005, compared to the same periods ended September 30, 2004. The amounts discussed below are on a pre-tax basis unless otherwise noted.

Electric Operating Revenues and Kilowatt-Hour Sales

Of our total electric operating revenues during the third quarter of 2005, approximately 42.1% were from residential customers, 30.1% from commercial customers, 16.2% from industrial customers, 4.1% from wholesale on-system customers, 4.3% from wholesale off-system transactions and 3.2% from miscellaneous sources, primarily transmission services. The breakdown of our customer classes has not significantly changed from the third quarter of 2004.

The amounts and percentage changes from the prior periods in kilowatt-hour ("kWh") sales and operating revenues by major customer class for on-system sales were as follows:

kWh Sales (in millions)

	3 Months Ended 2005	3 Months Ended 2004	% Change*	9 Months Ended 2005	9 Months Ended 2004	% Change*	12 Months Ended 2005	12 Months Ended 2004	% Change*
Residential	559.4	450.7	24.1%	1,440.0	1,303.6	10.5%	1,840.3	1,690.5	8.9%
Commercial	432.9	394.0	9.9	1,116.6	1,068.6	4.5	1,465.3	1,406.0	4.2
Industrial	305.9	292.7	4.5	829.3	820.8	1.0	1,093.9	1,093.2	0.1
Wholesale	95.8	83.8	14.3	250.5	231.7	8.1	324.5	302.0	7.4
Other**	30.4	27.7	9.9	83.9	80.8	3.8	111.1	106.3	4.6
Total On-System	1,424.4	1,248.9	14.1	3,720.3	3,505.5	6.1	4,835.1	4,598.0	5.2

Operating Revenues
($ in millions)

	3 Months Ended 2005***	3 Months Ended 2004	% Change*	9 Months Ended 2005***	9 Months Ended 2004	% Change*	12 Months Ended 2005***	12 Months Ended 2004	% Change*
Residential	$ 49.8	$ 36.9	34.9%	$ 114.8	$ 96.2	19.3%	$143.0	$123.4	15.9%
Commercial	35.5	29.6	20.0	80.7	71.2	13.3	101.9	91.8	11.0
Industrial	19.1	15.9	19.9	45.2	40.1	12.8	57.0	52.1	9.5
Wholesale	4.8	3.9	25.0	12.3	10.5	16.9	15.4	13.3	15.4
Other**	2.6	2.2	18.3	6.4	5.8	10.6	8.1	7.5	8.8
Total On-System	$ 111.8	$ 88.5	26.4	$259.4	$223.8	15.9	$325.4	$288.1	13.0

**Percentage changes are based on actual kWh sales and revenues and may not agree to the rounded amounts shown above.*
***Other kWh sales and other operating revenues include street lighting, other public authorities and interdepartmental usage.*
****Revenues include approximately $2.5 million of the Interim Energy Charge collected in the third quarter of 2005 and approximately $4.6 million collected in the first nine months of 2005 that are not expected to be refunded to customers. See discussion below.*

On-System Electric Transactions

KWh sales for our on-system customers increased 14.1% during the third quarter of 2005 as compared to the third quarter of 2004 primarily due to warmer temperatures during the third quarter of 2005 as compared to the same period in 2004, with a new record peak of 1,087 megawatts set on

July 21, 2005. Total cooling degree days (the number of degrees that the average temperature for that period was above 65 °F) for the third quarter of 2005 were 39.9% more than the same period last year and 15.9% more than the 20-year average. Revenues for our on-system customers increased approximately $23.3 million, or 26.4%, due to the warmer weather and rate increases. For analysis purposes we estimate the factors that contribute toward total revenues. The March 2005 Missouri rate increase and May 2005 Arkansas rate increase (discussed below) contributed an estimated $8.3 million to revenues in the third quarter of 2005 while continued sales growth contributed an estimated $2.7 million. Weather contributed an estimated $9.8 million and the collected IEC that is not expected to be refunded contributed approximately $2.5 million during the third quarter of 2005. Our customer growth was 1.69% in 2004 and 1.63% in 2003. We expect our annual customer growth to range from approximately 1.6% to 1.8% over the next several years, although our customer growth for the twelve months ended September 30, 2005, was 1.97%.

Residential and commercial kWh sales and revenues increased during the third quarter of 2005 due mainly to the warmer temperatures discussed above as well as being positively impacted by continued sales growth and 2005 Missouri and Arkansas rate increases.

Industrial kWh sales and revenues, which are not particularly weather sensitive, increased during the third quarter of 2005 due mainly to a continuing increase in sales growth and to the 2005 rate increases.

On-system wholesale kWh sales and revenues increased during the third quarter of 2005 reflecting the weather conditions discussed above. Revenues associated with these FERC-regulated sales increased more than the kWh sales as a result of the fuel adjustment clause applicable to such sales. This clause permits the distribution of changes in fuel and purchased power costs to these wholesale customers.

For the nine months ended September 30, 2005, kWh sales to our on-system customers increased approximately 6.1% while the associated revenues increased approximately $35.6 million, or 15.9%. Rate increases contributed an estimated $16.6 million to revenues with continued sales growth contributing an estimated $6.2 million and weather and other related factors contributing an estimated $8.2 million. The collected IEC that is not expected to be refunded contributed approximately $4.6 million during the nine months ended September 30, 2005. Residential and commercial kWh sales and associated revenues increased during the nine months ended September 30, 2005 due mainly to warmer temperatures in the second and third quarters of 2005, continued sales growth and the Missouri and Arkansas 2005 rate increases. Industrial kWh sales and revenues increased for the nine month period reflecting the third quarter increase in sales growth and the 2005 rate increases. On-system wholesale kWh sales increased, reflecting the weather conditions and continued sales growth discussed above. Revenues associated with these FERC-regulated sales increased more than the kWh sales as a result of the fuel adjustment clause applicable to such sales.

For the twelve months ended September 30, 2005, kWh sales to our on-system customers increased approximately 5.2% while the associated revenues increased approximately $37.3 million, or 13.0%, as compared to the same period ended September 30, 2004. Rate increases contributed an estimated $17.6 million to revenues, continued sales growth contributed an estimated $8.1 million and weather and other related factors contributed an estimated $7.0 million. The collected IEC that is not expected to be refunded contributed approximately $4.6 million during the twelve months ended September 30, 2005. Residential and commercial kWh sales and associated revenues increased during the twelve months ended September 30, 2005 due mainly to warmer temperatures in the second and third quarters of 2005, continued sales growth and the 2005 Missouri and Arkansas rate increases. Industrial kWh sales, which are not particularly weather sensitive, increased slightly while revenues increased 9.5%, reflecting the third quarter increase in sales growth and the 2005 rate increases. On-system wholesale kWh sales increased reflecting the weather conditions and continued sales growth discussed above. Revenues associated with these FERC-regulated sales increased more than the kWh sales as a result of the fuel adjustment clause applicable to such sales.

Rate Matters

The following table sets forth information regarding electric rate increases affecting the revenue comparisons discussed above:

Jurisdiction	Date Requested	Base Annual Increase Granted	Percent Increase Granted	Date Effective
Arkansas -Electric	July 14, 2004	595,000	7.66%	May 14, 2005
Missouri - Electric	April 30, 2004	$ 25,705,500	9.96%	March 27, 2005

On April 30, 2004, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $38,282,294, or 14.82%. Prior to the hearings, we were able to settle several miscellaneous issues with other parties to the case. On December 22, 2004, we, the MPSC Staff, the Office of the Public Counsel (OPC) and two intervenors filed a unanimous Stipulation and Agreement as to Certain Issues with the MPSC settling several of these issues. One of the issues we were able to agree on was a change in the recognition of pension costs allowing us to defer the Missouri portion of any costs above the amount included in this rate case as a regulatory asset. The amount of pension cost allowed in this rate case was approximately $3 million. This stipulation became effective on March 27, 2005 as part of the final Missouri Order described below. Therefore, the deferral of these costs began in the second quarter of 2005.

The MPSC issued a final order on March 10, 2005 approving an annual increase in base rates of approximately $25.7 million, or 9.96%, effective March 27, 2005. The order granted us a return on equity of 11%, an increase in base rates for fuel and purchased power at $24.68/MWH and an increase in depreciation rates. The new depreciation rates now include a cost of removal component of mass property (transmission, distribution and general plant costs). In addition, the order approved an annual IEC of approximately $8.2 million effective March 27, 2005 and expiring three years later. The IEC is $0.002131 per kilowatt hour of customer usage. The MPSC allowed us to use forecasted fuel costs rather than the traditional historical costs in determining the fuel portion of the rate increase. At the end of two years, an assessment will be made of the money collected from customers compared to the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates. If the excess of the amount collected over the greater of these two amounts is greater than $10 million, the excess over $10 million will be refunded to the customers. The entire excess amount of IEC, not previously refunded, will be refunded at the end of three years, unless the IEC is terminated earlier. Each refund will include interest at the current prime rate at the time of the refund. The IEC revenues recorded in the second and third quarters of 2005 did not recover all the Missouri related fuel and purchased power costs incurred in those quarters. From inception of the IEC through September 30, 2005, the costs of fuel and purchased power were approximately $7.0 million higher than the total of the costs in our base rates and the IEC recorded during the period. Future recovery of fuel and purchased power costs through the IEC are dependent upon a variety of factors, including natural gas prices, costs of non-contract purchased power, weather conditions, plant availability and coal deliveries. At September 30, 2005, no provision for refund has been recorded.

On March 25, 2005, we, the OPC, the Missouri Industrial Energy Consumers and Intervenors Praxair, Inc. and Explorer Pipeline Company, filed applications with the MPSC requesting the MPSC grant a rehearing with respect to the return on equity granted in the March 2005 Missouri rate case. The MPSC denied these applications on April 7, 2005. We and the OPC appealed this decision to the

Cole County Circuit Court. Briefs have been filed by all parties and oral argument is scheduled for January 4, 2006. A decision by the Circuit Court is expected thereafter.

On July 14, 2004, we filed a request with the APSC for an annual increase in base rates for our Arkansas electric customers in the amount of $1,428,225, or 22.1%. On May 13, 2005, the APSC granted an annual increase in electric rates for our Arkansas customers of approximately $595,000, or 7.66%, effective May 14, 2005. In September 2005, the APSC allowed us to adjust our annual ECR rate midway through the regulatory year due to higher gas prices with the adjusted interim rate effective October 1, 2005 through March 31, 2006.

On April 29, 2005, we filed a request with the Kansas Corporation Commission (KCC) for an increase in base rates for our Kansas electric customers in the amount of $4,181,078, or 24.64%. On October 4, 2005, we and the KCC Staff filed a Stipulated Settlement Agreement (Agreement) with the KCC. The Agreement calls for a $2.15 million rate increase and an Energy Cost Adjustment Clause (ECA), a fuel rider that will collect fuel costs in the future. In addition, we will be allowed to change our recognition of pension costs, deferring the Kansas portion of any costs above the amount included in this rate case as a regulatory asset. The Citizens' Utility Ratepayer Board, an intervenor in the proceedings, did not agree to this Agreement. A hearing was held on October 11, 2005 with a decision expected by the end of 2005. If the KCC accepts the Agreement in its entirety, the new rates will go into effect January 1, 2006.

On June 24, 2005, we filed a request with the MPSC for an annual increase in base rates for our Missouri water customers in the amount of $523,000, or 38%. Any new rates approved as a result of this request will not go into effect before 2006.

We expect the unprecedented high natural gas prices to continue to negatively impact our fuel and purchased power expenses in the near future. Given our limited ability to recover these added costs, we plan to file a Missouri rate case early in the first quarter of 2006 to request transition from the IEC to Missouri's new fuel adjustment mechanism. At this time, we cannot predict the outcome of this planned rate case filing.

We will continue to assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Off-System Transactions

In addition to sales to our own customers, we also sell power to other utilities as available and provide transmission service through our system for transactions between other energy suppliers. The following table sets forth information regarding these sales and related expenses for the applicable periods ended September 30:

	2005			2004		
	Three Months Ended	Nine Months Ended	Twelve Months Ended	Three Months Ended	Nine Months Ended	Twelve Months Ended
(in millions)						
Revenues	$ 5.8	$ 12.6	$ 14.4	$ 2.1	$ 9.1	$ 11.2
Expenses	4.3	8.7	9.8	1.2	5.2	6.6
Net*	$ 1.5	$ 3.9	$ 4.6	$ 1.0	$ 3.8	$ 4.6

**Differences could occur due to rounding.*

Revenues less expenses for the nine months ended and twelve months ended September 30, 2005 periods were virtually the same as the comparable periods in 2004. The increase in revenues less expenses for the three months ended September 30, 2005 as compared to the prior year period resulted primarily from increased sales of our gas-fired generation due to a shortage of available coal-fired generation on the open market. Companies that normally would have coal-fired energy to sell in the market were not doing so due to the coal shortages, pushing demand onto the gas-fired units. The related expenses are included in our discussions of purchased power costs below.

Operating Revenue Deductions

During the third quarter of 2005, total operating expenses increased approximately $24.8 million (33.9%) compared with the same period last year. Fuel costs increased approximately $19.1 million (108.6%) while purchased power costs increased $0.4 million (3.2%) during the third quarter of 2005. The increase in fuel costs was primarily due to increased generation by our gas fired units in the third quarter of 2005 (an estimated $7.4 million) combined with higher prices for both hedged and unhedged natural gas that we burned in our gas-fired units (an estimated $8.7 million). Increased coal costs contributed approximately $0.8 million to the total fuel increase while increased generation by our coal fired units added an estimated $0.3 million. These increased costs reflect a $5 million one-time pre-tax gain from unwinding part of a physical purchase of natural gas for the 2009 through 2011 period as part of our fuel management process. This gain was recognized in the current quarter as a decrease to fuel expense. This cost impact also includes the effect of increased September natural gas prices resulting, in part, from the effects of hurricane activity in the Gulf of Mexico. We estimate this cost impact to be approximately $2.4 million for the quarter. The increased usage was due in part to weather, as well as changes in the wholesale market impacted by coal delivery issues in the Midwest.

Regulated – other operating expenses increased approximately $0.7 million (5.3%) during the third quarter of 2005 as compared to the same period in 2004. This increase was primarily due to a $0.5 million increase in transmission and distribution expense, a $0.2 million addition to bad debt expense and a $0.1 million increase in employee pension expense, partially offset by a $0.2 million decrease in general administrative expense due to reduced costs associated with Sarbanes-Oxley Section 404 compliance. As discussed previously, effective with the second quarter of 2005, we began deferring a portion of our pension cost into a regulatory asset as authorized in our latest rate case. We have deferred approximately $1.0 million as of September 30, 2005.

Non-regulated operating expense for all periods presented is discussed below under "-Non-regulated Items".

Maintenance and repairs expense was virtually the same during the third quarter of 2005 as compared to the third quarter of 2004. Although maintenance costs at the Energy Center increased approximately $0.2 million in the third quarter of 2005 as compared to the same period in 2004, the increase was offset by a decrease of approximately $0.3 million in distribution maintenance expense in the third quarter of 2005.

Depreciation and amortization expense increased approximately $1.5 million (19.3%) during the quarter due to higher depreciation rates that became effective on March 27, 2005, as well as increased plant in service. The provision for income taxes increased approximately $1.5 million during the third quarter of 2005 due to increased income. Our effective federal and state income tax rate for the third quarter of 2005 was 33.4% as compared to 33.9% for the third quarter of 2004. Other taxes increased approximately $0.7 million (14.7%) during the quarter due to increased property taxes and municipal franchise taxes.

During the nine months ended September 30, 2005, total operating expenses increased approximately $38.6 million (18.4%) compared with the same period last year. Fuel costs increased approximately $32.1 million (61.0%) but were partially offset by a $2.3 million (6.0%) decrease in purchased power costs during the period. The increase in fuel costs was primarily due to increased generation by our gas fired units during the first nine months of 2005 (an estimated $12.1 million), combined with higher prices for both hedged and unhedged natural gas that we burned in our gas-fired units (an estimated $15.9 million). Increased coal costs contributed approximately $2.1 million to the total fuel increase. The decrease in purchased power costs primarily reflected a shift from serving our energy needs with purchased power to generating our own power reflecting that it was more economical to run our own generating units during the nine months ended September 30, 2005 than to purchase power. The net increase in fuel and purchased power costs during the nine months ended September 30, 2005 as compared to the same period last year was $29.8 million (32.8%).

Regulated - other operating expenses for the first nine months of 2005 increased approximately $2.2 million (5.6%) primarily due to a $1.2 million increase in employee health care costs, a $1.2 million increase in employee pension expense and a $0.6 million increase in transmission and distribution expense, partially offset by a $0.3 million decrease in general administrative expense due to reduced costs associated with Sarbanes-Oxley Section 404 compliance and a $0.4 million decrease in stock compensation costs.

Maintenance and repairs expense decreased $0.8 million (4.8%) for the nine months ended September 30, 2005 compared to the same period in 2004 primarily due to decreased maintenance costs at the Energy Center during the second quarter of 2005 as compared to the same period in 2004 when the Energy Center had maintenance costs related to generator repairs.

Depreciation and amortization expense increased approximately $3.4 million (14.7%) during the nine-month period due to increased depreciation rates and increased plant in service. Total provisions for income taxes increased $1.1 million (10.3%) due to increased taxable income. Our effective federal and state income tax rate for the nine months ended September 30, 2005 was 33.4% as compared to 33.8% for the same period in 2004. Other taxes increased $1.2 million (8.5%) during the nine months ended September 30, 2005 due mainly to increased property taxes reflecting our additions to plant in service and increased municipal franchise taxes.

During the twelve months ended September 30, 2005, total operating expenses increased approximately $42.9 million (15.9%) compared with the same period in 2004. Total fuel costs increased approximately $33.8 million (53.9%) but were partially offset by a decrease in total purchased power costs of approximately $1.2 million (2.3%) during the twelve-month period. The increase in fuel costs was due to increased generation by our gas-fired units (an estimated $14.1 million) combined with higher prices for both hedged and unhedged natural gas that we burned in our gas-fired units (an estimated $15.8 million). Increased coal costs contributed approximately $2.2 million to the total fuel increase. The decrease in purchased power costs primarily reflected a shift from serving our energy needs with purchased power to generating our own power reflecting that it was more economical to run our own generating units during the twelve months ended September 30, 2005 than to purchase power. The net increase in fuel and purchased power costs during the twelve months ended September 30, 2005 as compared to the same period last year was $32.6 million (28.5%).

Regulated – other operating expenses increased approximately $3.4 million (6.7%) during the twelve months ended September 30, 2005, compared to the same period last year due primarily to increases in employee health care of approximately $1.8 million, employee pension expense of approximately $1.3 million and a $0.6 million increase in transmission and distribution expense. These increases were partially offset by a decrease in regulatory commission expense of approximately $0.3 million.

Maintenance and repairs expense decreased approximately $1.1 million (5.0%) during the twelve months ended September 30, 2005 as compared to the same period in 2004 primarily due to a $1 million insurance deductible recorded to expense in the first quarter of 2004 related to the maintenance on the Energy Center's Unit No. 2 which experienced a rotating blade failure on January 7, 2004 (which caused damage throughout the machine) and to the second quarter maintenance costs related to generator repairs at the Energy Center.

Depreciation and amortization expense increased approximately $3.8 million (12.7%) for the twelve month period due to increased depreciation rates and increased plant in service. Total provisions for income taxes decreased $0.5 million (3.8%) due to decreased taxable income. Our effective federal and state income tax rate for the twelve months ended September 30, 2005 was 33.7% as compared to 33.2% for the same period in 2004. Other taxes increased approximately $1.6 million (8.9%) due to increased property taxes reflecting our additions to plant in service and increased municipal franchise taxes.

Non-regulated Items

Our non-regulated businesses, which we operate through our wholly-owned subsidiary EDE Holdings, Inc., include leasing of fiber optics cable and equipment (which we are also using in our own utility operations), Internet access, close-tolerance custom manufacturing and customer information system software services. We evaluated our non-regulated businesses for impairment at December 31, 2004, updated our analysis at September 30, 2005, and believe, based on this analysis, that no impairment exists based on our forecast of future net cash flows. However, failure to achieve forecasted cash flows could result in impairment in the future.

During the third quarter of 2005, total non-regulated operating revenue increased approximately $1.3 million (24.6%) while total non-regulated operating expense increased approximately $0.9 million (17.2%) compared with the same period in 2004. The increase in both operating revenues and expenses was mainly attributable to MAPP, the close-tolerance custom manufacturing business in which we own a 52% interest.

Our non-regulated businesses generated a $0.2 million net loss in the third quarter of 2005 as compared to a $0.4 million net loss in the third quarter of 2004.

For the nine months ended September 30, 2005, total non-regulated operating revenue increased approximately $2.1 million (13.2%) while total non-regulated operating expense increased approximately $1.8 million (11.0%) compared with the same period in 2004. The increase in operating revenue was mainly attributable to MAPP while the increase in expense was due mainly to the activities of MAPP and to Conversant, a software company in which we own a 100% interest. Conversant markets Customer Watch, an Internet-based customer information system software.

Our non-regulated businesses generated a $1.1 million net loss for both the nine months ended September 30, 2005 and the same period in 2004.

For the twelve-months ended September 30, 2005, total non-regulated operating revenue increased approximately $1.9 million (8.8%) while total non-regulated operating expense increased approximately $3.0 million (13.6%) compared with the same period in 2004. The increase in both revenues and expenses for the twelve-month-ended period was primarily due to MAPP.

Our non-regulated businesses generated a $1.8 million net loss for the twelve-months ended September 30, 2005 as compared to a $1.1 million net loss for the same period in 2004.

Nonoperating Items

Total allowance for funds used during construction (AFUDC) increased $0.1 million for the third quarter of 2005 as compared to the same period in 2004, $0.1 million for the first nine months of 2005 as compared to the first nine months of 2004 and $0.3 million during the twelve months ended September 30, 2005 as compared to the prior year due to higher levels of construction for those periods ended September 30, 2005.

Total interest charges on long-term debt decreased $0.2 million (3.1%) during the third quarter of 2005 compared to the same period last year and $0.4 million (2.1%) for the nine months ended September 30, 2005 as compared to the same period in 2004 reflecting the refinancing we accomplished in June 2005 by calling a higher interest debt issue and replacing it with a debt issue at a lower interest rate. Total interest charges on long-term debt decreased $0.5 million (1.8%) for the twelve months ended September 30, 2005 as compared to the same period in 2004, also reflecting the refinancing we accomplished in November 2003 by calling higher interest debt issues and replacing them with debt issues at lower interest rates.

Other Comprehensive Income

The change in the fair value of the effective portion of our open gas contracts and our interest rate derivative contracts and the gains and losses on contracts settled during the periods being reported, including the tax effect of these items, are reflected in our Consolidated Statement of Comprehensive Income. This net change is recorded as accumulated other comprehensive income in the capitalization section of our balance sheet and does not affect net income or earnings per share. All of these contracts have been designated as cash flow hedges. The unrealized gains and losses accumulated in other comprehensive income are reclassified to fuel, or interest expense, in the periods in which the hedged transaction is actually realized or no longer qualifies for hedge accounting.

The following table sets forth the pre-tax (gains)/losses of our natural gas and interest rate contracts settled and reclassified, the pre-tax change in the fair market value (FMV) of our open contracts and the tax effect in Other Comprehensive Income (in millions) for the presented periods ending September 30,:

	3 Months Ended 2005	3 Months Ended 2004	9 Months Ended 2005	9 Months Ended 2004	12 Months Ended 2005	12 Months Ended 2004
Natural gas contracts settled *(1)*	$ (3.4)	$ (4.0)	$ (3.6)	$ (9.2)	$ (5.9)	$ (9.9)
Interest rate contracts settled	0.0	0.0	1.4	0.0	1.4	(5.1)
Total contracts settled	$ (3.4)	$ (4.0)	$ (2.2)	$ (9.2)	$ (4.5)	$ (15.0)
Change in FMV of open contracts for natural gas	$ 15.6	$ 4.1	$ 33.1	$ 7.7	$ 29.7	$ 10.8
Change in FMV of open contracts for interest rates	0.0	0.0	(1.4)	0.0	(1.4)	2.1
Total change in FMV of contracts	$ 15.6	$ 4.1	$ 31.7	$ 7.7	$ 28.3	$ 12.9
Taxes - natural gas	$ (4.6)	$ 0.0	$ (11.2)	$ 0.6	$ (9.0)	$ (0.3)
Taxes – interest rates	0.0	0.0	0.0	0.0	0.0	1.1
Total taxes	$ (4.6)	$ 0.0	$ (11.2)	$ 0.6	$ (9.0)	$ 0.8
Total change in OCI - net of tax	$ 7.6	$ 0.1	$ 18.3	$ (0.9)	$ 14.8	$ (1.3)

(1) Reflected in fuel expense

Our average cost for our open natural gas hedges increased from $4.703/Dth at June 30, 2005 to $5.758/Dth at September 30, 2005.

Environmental

In mid-December 2003, the EPA issued proposed regulations with respect to SO2 and NOx from coal-fired power plants in a proposed rulemaking known as the Clean Air Interstate Rule (CAIR). The final CAIR was issued by the EPA on March 10, 2005 and will affect 28 states, including Missouri, where our Asbury and Iatan plants are located, but excluding Kansas, where our Riverton plant is located. Also in mid-December 2003, the EPA issued the proposed Clean Air Mercury Rule (CAMR) regulations for mercury emissions by power plants under the requirements of the 1990 Amendments to the Clean Air Act. The final CAMR was issued March 15, 2005. It is possible that we may need to make some expenditures as early as 2007 in order to meet the compliance date of January 1, 2009 for mercury analyzers and the mercury emission compliance date of January 1, 2010. The CAIR and the CAMR were issued as a result of delays and setbacks in the legislative process for the President's Clear Skies Act legislation, which would have imposed different restrictions on SO2, NOx and mercury emissions. The CAIR and the CAMR are not directed to specific generation units, but instead, require the states (including Missouri and Kansas) to develop State Implementation Plans (SIP) within the next 12 months in order to comply with specific NOx, SO2 and/or mercury state-wide annual budgets (although Kansas is not covered by the NOx or SO2 requirements). Until these plans are finalized, we cannot determine the required emission rates of NOx, SO2 and mercury for the Asbury or Iatan plants in Missouri or the required mercury emission rate for the Riverton plant in Kansas. Also, the SIPs will likely include allowance trading programs for NOx, SO2 and/or mercury that could allow compliance without additional capital expenditures.

As part of our Experimental Regulatory Plan filed with the MPSC, we have committed to install pollution control equipment required at the Iatan plant by 2008 which will include an SCR system, a Flue Gas Desulphurization (FGD) system and a Bag House, with our share of the capital cost estimated at $30 million. Approximately $17 million of this amount was already included in our capital expenditure budget for equipment to be installed by 2008. Of the remaining amount, $11 million is expected to be incurred in 2007, and is now included in the new capital expenditures budget approved by our Board of Directors on July 28, 2005. For additional information, see "-Liquidity and Capital Resources – Capital Requirements and Investing Activities" below.

As part of our Experimental Regulatory Plan we also committed to add an SCR at Asbury which we expect to be in service before January 2009. We are currently developing a schedule to perform the tie-ins with the existing plant during our scheduled 2007 fall outage. Our current cost estimate for an SCR at Asbury is $30 million. We also expect that additional pollution control equipment will be economically justified at the Asbury plant sometime prior to 2015 and may include a FGD and a Bag House at an estimated capital cost of $75 million. At this time we do not anticipate the installation of additional pollution control equipment at the Riverton plant.

LIQUIDITY AND CAPITAL RESOURCES

Cash Provided by Operating Activities

Our net cash flows provided by operating activities increased $21.5 million during the nine months ended September 30, 2005 as compared to the nine months ended September 30, 2004. This reflects, in part, a $2.6 million increase in net income, which includes the $5 million one-time gain resulting from unwinding part of a physical purchase of natural gas for the 2009 through 2011 period. Changes in adjustments to net income for non-cash items were $0.5 million more during the nine months ended September 30, 2005 versus the same period last year. In addition, an $18.3 million increase due to reduced working capital requirements (primarily as a result of increased accounts payable and accrued liabilities) positively impacted cash flows. The increased accounts payable reflects the receipt of $10 million in margin collateral from a counterparty in relation to credit account support related to our hedging program.

Given recent market returns, we could face a position at December 31, 2005 where our accumulated pension benefit obligation exceeds the fair value of our plan assets. If this situation exists, we may elect to make an additional cash contribution to our pension plan. The amount of the liability, or cash contribution, if any, will depend upon asset returns experienced in the remainder of 2005. There would be no effect to net income if this liability is recognized or if a cash contribution is made.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities increased $27.3 million during the nine months ended September 30, 2005 as compared to the nine months ended September 30, 2004, primarily reflecting additions to our transmission and distribution systems and construction expenditures for the new combustion turbine at Riverton.

Our capital expenditures totaled approximately $15.3 million during the third quarter of 2005 compared to approximately $10.3 million for the same period in 2004. For the nine months ended September 30, 2005, capital expenditures totaled approximately $57.6 million compared to approximately $30.2 million for the same period in 2004. These capital expenditures include AFUDC, capital expenditures to retire assets and benefits from salvage.

A breakdown of the capital expenditures for the quarter and nine months ended September 30, 2005 is as follows:

	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2005
	(in millions)	
Distribution and transmission system additions	$ 8.0	$ 26.4
Additions and replacements – Asbury	0.3	4.2
Additions and replacements – Riverton, Iatan, Ozark Beach, Energy Center, State Line and State Line Combined Cycle	0.6	2.7
New generation – Riverton combustion turbine	3.9	18.5
Fiber optics (non-regulated)	0.4	1.5
Transportation	0.6	0.9
New generation – other	0.0	0.2
Other non-regulated capital expenditures	0.1	0.5
Other	1.2	3.1
Retirements and salvage (net)	0.2	(0.4)
Total	$ 15.3	$ 57.6

Approximately all of our cash requirements for capital expenditures during the first nine months of 2005 were satisfied internally from operations (funds provided by operating activities less dividends paid). We currently expect that internally generated funds will provide approximately 33% of the funds required for the remainder of our 2005 capital expenditures. We had originally estimated that our capital expenditures for 2006 and 2007 would be approximately $86.0 million and $88.4 million, respectively (including AFUDC). Due to planned new generation and our proposed Experimental Regulatory Plan, we have revised our estimate of these capital expenditures to approximately $100.4 million for 2006 and $140.9 million for 2007. As in the past, we intend to utilize short-term debt or the proceeds of sales of long-term debt or common stock (including common stock sold under our Employee Stock Purchase Plan, our Dividend Reinvestment and Stock Purchase Plan, and our 401(k) Plan and ESOP) to finance any additional amounts needed beyond those provided by operating activities for such capital expenditures. We will continue to utilize short-term debt as needed to support normal operations or other temporary requirements.

Financing Activities

Our net cash flows used in financing activities decreased $4.0 million during the first nine months of 2005 as compared to the first nine months of 2004 resulting in a $31.4 million use of cash in the current year. Our net cash flows used in financing activities were primarily affected by borrowing and repayment of short-term debt (commercial paper).

On December 17, 2003, we sold to the public in an underwritten offering, 2,000,000 newly issued shares of our common stock for $42.3 million. The net proceeds of approximately $40.3 million were used to repay short-term debt and for other general corporate purposes. On January 8, 2004, the underwriters purchased an additional 300,000 shares for approximately $6.1 million to cover over-allotments. The proceeds were added to our general funds.

On April 1, 2005, we redeemed our $10 million First Mortgage Bonds, 7.60% Series due April 1, 2005, using short-term debt. On June 27, 2005, we issued $40 million aggregate principal amount of our Senior Notes, 5.8% Series due 2035, for net proceeds of approximately $39.4 million less $0.1 million of legal fees. We used the net proceeds from this issuance to redeem all $30 million aggregate principal amount of our First Mortgage Bonds, 7.75% Series due 2025 for approximately $31.3 million, including interest and a redemption premium, and to repay short-term debt. The $1.2 million redemption premium paid in connection with the redemption of these first mortgage bonds, together with $2.4 million of remaining unamortized loss on reacquired debt and $0.3 million of unamortized debt expense, were recorded as a regulatory asset and are being amortized as interest expense over the life of the 2035 Notes. We had entered into an interest rate derivative contract in May 2005 to hedge against the risk of a rise in interest rates impacting the 2035 Notes prior to their issuance. Costs associated with the interest rate derivative (primarily due to interest rate fluctuations) amounted to approximately $1.4 million and were recorded as a regulatory asset and are being amortized over the life of the 2035 Notes.

We have an effective shelf registration statement with the SEC under which $400 million of our common stock, unsecured debt securities, preference stock and first mortgage bonds (subject to receipt of state regulatory approvals) are available for issuance. We plan to use a portion of the proceeds from issuances under this new shelf to fund our proposed acquisition of the Missouri natural gas distribution operations from Aquila, Inc.

On July 15, 2005, we entered into a $150 million five year unsecured credit agreement with UMB Bank, N.A., as administrative agent, Bank of America, N.A., as syndication agent, and the other lenders party thereto. This agreement replaces our pre-existing $100 million unsecured credit agreement, which was terminated upon entering into the new agreement. The credit agreement provides for $150 million of revolving loans to be available for working capital, general corporate purposes and to back-up our use of commercial paper. Interest on borrowings under the credit agreement accrues at a rate equal to, at our option, (i) the bank's prime commercial rate plus a margin or (ii) LIBOR plus a margin, in each case based on our then current credit ratings. This agreement requires our total indebtedness (which does not include our note payable to the securitization trust) to be less than 62.5% of our total capitalization at the end of each fiscal quarter and our EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to be at least two times our interest charges (which includes interest on the note payable to the securitization trust) for the trailing four fiscal quarters at the end of each fiscal quarter. Failure to maintain these ratios will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. We are in compliance with these ratios as of September 30, 2005. This credit agreement is also subject to cross-default if we default on in excess of $10 million in the aggregate on our other indebtedness. There were no outstanding borrowings under this agreement at September 30, 2005.

Restrictions in our mortgage bond indenture could affect our liquidity. The Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the twelve months ended September 30, 2005 would permit us to issue approximately $240.3 million of new first mortgage bonds based on this test with an assumed interest rate of 6.0%.

As of September 30, 2005, the ratings for our securities were as follows:

	Moody's	Standard & Poor's
First Mortgage Bonds	Baa1	A-
First Mortgage Bonds - Pollution Control Series	Aaa	AAA
Senior Notes	Baa2	BBB-
Commercial Paper	P-2	A-2
Trust Preferred Securities	Baa3	BB+

Moody's affirmed our ratings on May 13, 2005 and revised their rating outlook on us from negative to stable. On September 22, 2005, Standard & Poor's, reflecting our announcement of our proposed acquisition of Aquila, Inc.'s Missouri natural gas properties, placed our corporate credit rating on credit watch with negative implications. S&P stated that the acquisition comes in addition to our embarking on a capital spending program that is significantly higher than historical levels and will be partially debt financed. In addition, S&P stated that the pressure of currently high commodity prices on our cash flow relative to the level in rate recovery could cause a weakening of credit protection measures during a period when our debt levels are increasing as an additional factor in their decision. These ratings indicate the agencies' assessment of our ability to pay interest, distributions, dividends and principal on these securities. The lower the rating the higher our financing costs will be when our securities are sold. Ratings below investment grade (investment grade is Baa3 or above for Moody's and BBB- or above for Standard & Poor's) may also impair our ability to issue short-term debt, commercial paper or other securities or make the marketing of such securities more difficult.

In late September we entered into an agreement with Fitch Ratings to initiate coverage of us and to assign ratings to our outstanding debt securities. We anticipate a rating announcement during the fourth quarter of 2005.

CONTRACTUAL OBLIGATIONS

Set forth below is information summarizing our contractual obligations as of September 30, 2005:

	Payments Due by Period (in millions)				
Contractual Obligations*	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt (w/o discount)	$ 358.1	$ -	$ -	$ 70.0	$ 288.1
Note payable to securitization trust	50.0	-	-	-	50.0
Interest on long-term debt	431.6	26.0	52.4	48.6	304.6
Capital lease obligations	1.6	0.5	0.5	0.6	-
Operating lease obligations****	307.1	11.3	27.5	28.0	240.3
Purchase obligations**	322.6	75.4	99.5	73.8	73.9
Open purchase orders	33.5	16.3	16.2	1.0	-
Other long-term liabilities***	2.7	0.5	2.2	-	-
Total Contractual Obligations	$ 1,507.2	$ 130.0	$ 198.3	$ 222.0	$ 956.9

**Some of our contractual obligations have price escalations based on economic indices, but we do not anticipate these escalations to be significant.*

***Includes fuel and purchased power contracts.*
****Other Long-term Liabilities primarily represents 100% of the long-term debt issued by Mid-America Precision Products, LLC. As of September 30, 2005, EDE Holdings, Inc. was the 52% guarantor of a $2.5 million note included in this total amount.*
*****Includes monthly prepayments for wind energy from the Elk River Wind Farm which will be adjusted for actual wind purchases.*

DIVIDENDS

Holders of our common stock are entitled to dividends if, as, and when declared by the Board of Directors, out of funds legally available therefore, subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings (which is essentially our accumulated net income less dividend payouts). As of September 30, 2005, our retained earnings balance was $26.8 million, compared to $35.3 million as of September 30, 2004.

Our diluted earnings per share were $0.87 for the nine months ended September 30, 2005 and were $0.86, $1.29 and $1.19 for the years ended December 31, 2004, 2003 and 2002, respectively. Dividends paid per share were $0.96 for the nine months ended September 30, 2005 and $1.28 for each of the years ended December 31, 2004, 2003 and 2002.

In addition, the Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the earned surplus (as defined in the Mortgage) accumulated subsequent to August 31, 1944, or the date of succession in the event that another corporation succeeds to our rights and liabilities by a merger or consolidation. As of September 30, 2005, our level of earned surplus did not prevent us from issuing dividends. In addition, under certain circumstances (including defaults thereunder), our Junior Subordinated Debentures, 8-1/2% Series due 2031, reflected as a note payable to securitization trust on our balance sheet, held by Empire District Electric Trust I, an unconsolidated securitization trust subsidiary, may also restrict our ability to pay dividends on our common stock.

OFF-BALANCE SHEET ARRANGEMENTS

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

CRITICAL ACCOUNTING POLICIES

The March MPSC rate order approved an annual IEC of approximately $8.2 million effective March 27, 2005 and expiring three years later, which allows us to recover Missouri jurisdictional variable fuel and purchased power costs we incur within a range (collar) of $21.97/Mwh (floor) and $24.11/Mwh (ceiling). The IEC is $0.002131 per kilowatt hour of customer usage. This revenue is recorded by revenue class when service is provided to the customer. If the Missouri variable fuel and purchased power $/Mwh is below the floor, we record a provision for refund of the entire IEC actual recorded dollars. If the Missouri variable fuel and purchased power $/Mwh is above the ceiling, we record all of the IEC collected as revenue. If the Missouri variable fuel and purchased power $/Mwh falls within the collar, the difference between Missouri ceiling dollars and Missouri variable fuel and purchased power dollars will be the provision for refund. The difference between the IEC actual recorded dollars and the provision for refund is the IEC we record as revenue. At each balance sheet date, we evaluate the probability that we would be required to refund either a portion or all of the amounts collected under the IEC to ratepayers. At September 30, 2005, no provision for refund has been recorded.

See "Item 7 – *Managements Discussion* and Analysis of Financial Condition and Results of Operations" in our Annual Report Form 10-K for the year ended December 31, 2004 for a discussion of additional critical accounting policies.

RECENTLY ISSUED ACCOUNTING STANDARDS

See Note 2 of "Notes to Consolidated Financial Statements (Unaudited)".

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the exposure to a change in the value of a physical asset or financial instrument, derivative or non-derivative, caused by fluctuations in market variables such as interest rates or commodity prices. We handle our commodity market risk in accordance with our established Energy Risk Management Policy, which may include entering into various derivative transactions. We utilize derivatives to manage our gas commodity market risk and to help manage our exposure resulting from purchasing most of our natural gas on the volatile spot market for the generation of power for our native-load customers. See Note 3 of "Notes to Consolidated Financial Statements (Unaudited)" for further information.

Interest Rate Risk. We are exposed to changes in interest rates as a result of financing through our issuance of commercial paper and other short-term debt. We manage our interest rate exposure by limiting our variable-rate exposure (applicable to commercial paper and borrowings under our unsecured credit agreement) to a certain percentage of total capitalization, as set by policy, and by monitoring the effects of market changes in interest rates.

If market interest rates average 1% more in 2005 than in 2004, our interest expense would increase, and income before taxes would decrease by less than $100,000. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2004. There was no outstanding commercial paper as of September 30, 2005. These analyses do not consider the effects of the reduced level of overall economic activity that could exist in such an environment. In the event of a significant change in interest rates, management would likely take actions to further mitigate its exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in our financial structure.

Commodity Price Risk. We are exposed to the impact of market fluctuations in the price and transportation costs of coal, natural gas, and electricity and employ established policies and procedures to manage the risks associated with these market fluctuations, including utilizing derivatives.

We satisfied 70.5% of our 2004 fuel supply need through coal. Approximately 90% of our 2004 coal supply was Western coal. We have contracts and have accepted binding proposals to supply fuel for our coal plants through 2007. These contracts and accepted proposals satisfy approximately 92% of our anticipated fuel requirements for 2006, and 63% of our 2007 requirements for our Asbury and Riverton coal plants. In order to manage our exposure to fuel prices, future coal supplies will be acquired using a combination of short-term and long-term contracts.

We are exposed to changes in market prices for natural gas we must purchase to run our combustion turbine generators. Our natural gas procurement program is designed to minimize our risk from volatile natural gas prices. We enter into physical forward and financial derivative contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expense and improve predictability. We expect that increases in gas prices will be partially offset by realized gains under financial derivative transactions. As of October 28, 2005, 69.9%, or 790,000 Dths's, of our anticipated volume of natural gas usage for November and December 2005 is hedged. See Note 3 of "Notes to Consolidated Financial Statements (Unaudited)" for further information.

Credit Risk. We are exposed to credit risk by our use of derivative financial instruments. Credit risk is the risk that the counterparty might fail to fulfill its performance obligations under contractual terms. Our credit risk is partially mitigated by our policy to require deposits from counterparties when their exposure to us exceeds certain thresholds. Our Risk Management Oversight Committee, which consists of senior management, has adopted credit risk and procedures policies and provides oversight in the monitoring of counterparty creditworthiness.

Item 4. Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the SEC's rules and forms, of information to be required to be disclosed by us in reports that we file or submit under the Exchange Act.

There have been no changes in our internal control over financial reporting that occurred during the third quarter of 2005 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

On April 28, 2005, the Company announced that Laurie A. Delano had been elected to the positions of Assistant Secretary and Assistant Treasurer and that, effective August 1, 2005, Ms. Delano would assume the positions of Controller and Principal Accounting Officer of the Company. Darryl L. Coit, who previously held the positions of Controller, Assistant Secretary, Assistant Treasurer and Principal Accounting Officer announced his retirement effective July 31, 2005.

PART II. OTHER INFORMATION

Item 5. Other Information.

For the twelve months ended September 30, 2005, our ratio of earnings to fixed charges was 2.25x. See Exhibit (12) hereto.

Item 6. Exhibits.

(12) Computation of Ratio of Earnings to Fixed Charges.

(31)(a) Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31)(b) Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(32)(a) Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

(32)(b) Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

* This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 or any other provision of the Securities Exchange Act of 1934, as amended.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE EMPIRE DISTRICT ELECTRIC COMPANY
Registrant

By **/s/ Gregory A. Knapp**
Gregory A. Knapp
Vice President – Finance and Chief Financial Officer

By **/s/ Laurie A. Delano**
Laurie A. Delano
Controller, Assistant Secretary and Assistant Treasurer
and Principal Accounting Officer

November 9, 2005

EXHIBIT (12)

COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

		Twelve Months Ended September 30, 2005
Income before provision for income taxes and fixed charges (Note A)	$	65,882,247
Fixed charges:		
Interest on first mortgage bonds and secured debt	$	9,389,031
Amortization of debt discount and expense less premium		1,946,344
Interest on short-term debt		170,424
Interest on unsecured long-term debt		12,916,796
Interest on note payable to securitization trust		4,250,000
Other interest		519,827
Rental expense representative of an interest factor (Note B)		28,101
Total fixed charges	**$**	**29,220,523**
Ratio of earnings to fixed charges		2.25x

NOTE A: For the purpose of determining earnings in the calculation of the ratio, net income has been increased by the provision for income taxes, non-operating income taxes, minority interest and by the sum of fixed charges as shown above.

NOTE B: One-third of rental expense (which approximates the interest factor).

Exhibit (31)(a)

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, William L. Gipson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Empire District Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the period presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2005

By: /s/ William L. Gipson
Name: William L. Gipson
Title: President and Chief Executive Officer

Exhibit (31)(b)

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Gregory A. Knapp, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Empire District Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the period presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2005

By: /s/ Gregory A. Knapp
Name: Gregory A. Knapp
Title: Vice President - Finance and Chief Financial Officer

Exhibit (32)(a)

Certification Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of The Empire District Electric Company (the "Company") on Form 10-Q for the period ending September 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), William L. Gipson, as Chief Executive Officer of the Company, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

By <u>/s/ William L. Gipson</u>
Name: William L. Gipson
Title: President and Chief Executive Officer

Date: November 9, 2005

A signed original of this written statement required by Section 906 or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to The Empire District Electric Company and will be retained by The Empire District Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit (32)(b)

Certification Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of The Empire District Electric Company (the "Company") on Form 10-Q for the period ending September 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Gregory A. Knapp, as Chief Financial Officer of the Company, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

By /s/ Gregory A. Knapp
Name: Gregory A. Knapp
Title: Vice President - Finance and Chief Financial Officer

Date: November 9, 2005

A signed original of this written statement required by Section 906 or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to The Empire District Electric Company and will be retained by The Empire District Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.