UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

		_		 -	
	(Mark C	ne)			
	X	Quarterly report pursua For the quarterly period		, ,	ies Exchange Act of 1934
		Transition report pursua	ant to Section 13 or	15(d) of the Securi	ties Exchange Act of 1934
		For the transition period	d from	to	
		(Commission file nu	mber: 1-3368	
		THE EMPIRE	DISTRICT E		OMPANY
		Kansas (State of Incorporati	ion)	(I.	44-0236370 R.S. Employer Identification No.)
	602	S. Joplin Avenue, Jo (Address of principal execu-			64801 (zip code)
		Registra	ant's telephone num	nber: (417) 625-510	0
15(d) of the regis	the Sec strant w	curities Exchange Act o	f 1934 during the p	preceding 12 month	uired to be filed by Section 13 or as (or for such shorter period that a such filing requirements for the
site, if an S-T (§23	ny, ever 32.405 (y Interactive Data File r	equired to be subm he preceding 12 m	nitted and posted punionths (or for such	and posted on its corporate Web ursuant to Rule 405 of Regulation shorter period that the registrant
accelera	ated filer	check mark whether the control of the character of the control of the character of the char	company. See the	e definitions of "larg	iler, an accelerated filer, a non- ge accelerated filer," "accelerated
		erated filer <u>√</u> rated filer (Do not ch	neck if a smaller rep	porting company)	Accelerated filer Smaller reporting company
Indica Act). Y	•		registrant is a shell	company (as define	ed in Rule 12b-2 of the Exchange
As of	July 30	, 2013, 42,854,223 shar	res of common stoo	k were outstanding	

THE EMPIRE DISTRICT ELECTRIC COMPANY

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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, impacts from the 2011 tornado, 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:

- weather, business and economic conditions, recovery and rebuilding efforts relating to the 2011 tornado and other factors which may impact sales volumes and customer growth;
- the costs and other impacts resulting from natural disasters, such as tornados and ice storms;
- the amount, terms and timing of rate relief we seek and related matters;
- the results of prudency and similar reviews by regulators of costs we incur, including capital expenditures, fuel
 and purchased power costs and Southwest Power Pool (SPP) regional transmission organization (RTO)
 expansion costs, including any regulatory disallowances that could result from prudency reviews;
- legislation and regulation, including environmental regulation (such as NOx, SO₂, mercury, ash and CO₂) and health care regulation;
- competition and markets, including the SPP Energy Imbalance Services Market and SPP Day-Ahead Market and the impact of energy efficiency and alternative energy sources;
- electric utility restructuring, including ongoing federal activities and potential state activities;
- volatility in the credit, equity and other financial markets and the resulting impact on our short term debt costs and our ability to issue debt or equity securities, or otherwise secure funds to meet our capital expenditure, dividend and liquidity needs;
- the effect of changes in our credit ratings on the availability and cost of funds;
- the performance of our pension assets and other post employment benefit plan assets and the resulting impact on our related funding commitments;
- the periodic revision of our construction and capital expenditure plans and cost and timing estimates;
- our exposure to the credit risk of our hedging counterparties;
- changes in accounting requirements (including the potential consequences of being required to report in accordance with IFRS rather than U. S. GAAP);
- unauthorized physical or virtual access to our facilities and systems and acts of terrorism, including, but not limited to, cyber-terrorism;
- the timing of accretion estimates, and integration costs relating to completed and contemplated acquisitions and the performance of acquired businesses:
- rate regulation, growth rates, discount rates, capital spending rates, terminal value calculations and other factors
 integral to the calculations utilized to test the impairment of goodwill, in addition to market and economic
 conditions which could adversely affect the analysis and ultimately negatively impact earnings;
- the success of efforts to invest in and develop new opportunities;
- 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;
- interruptions or changes in our coal delivery, gas transportation or storage agreements or arrangements;
- operation of our electric generation facilities and electric and gas transmission and distribution systems, including the performance of our joint owners;
- costs and effects of legal and administrative proceedings, settlements, investigations and claims; and
- other circumstances affecting anticipated rates, revenues and costs.

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.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

CONSOCIDATED STATEMENTS OF INCOME (GNAODITED)		Three Mor		ded
		2013	3 00,	2012
	(00	00's except pe	r share	amounts)
Operating revenues:				
Electric	\$	127,026	\$	124,091
Gas		7,777		5,804
Other		1,843		1,737
O		136,646		131,632
Operating revenue deductions: Fuel and purchased power		42,013		45,528
Cost of natural gas sold and transported		3,113		1,769
Regulated operating expenses		26,647		22,844
Other operating expenses		872		771
Maintenance and repairs		9,933		10,797
Depreciation and amortization		17,635		15,068
Provision for income taxes		7,042		6,673
Other taxes		8,281		7,420
		115,536		110,870
Operating income		21,110		20,762
Other income and (deductions):		•		•
Allowance for equity funds used during construction		867		53
Interest income		10		123
Provision for other income taxes		(7)		(87)
Other - non-operating expense, net		(290)		(202)
		<u>580</u>		(113)
Interest charges:		40.400		0.007
Long-term debt		10,190		9,637
Short-term debt Allowance for borrowed funds used during construction		12 (472)		129 (118)
Other		302		293
Outo		10,032		9,941
		_		
Net income	<u>\$</u>	<u>11,658</u>	<u>\$</u>	<u> 10,708</u>
Weighted average number of common shares outstanding - basic		42,707		42,197
Weighted average number of common shares outstanding - diluted		42,727		42,220
Total earnings per weighted average share of common stock – basic and diluted	<u>\$</u>	0.27	<u>\$</u>	0.25
Dividends declared per share of common stock	<u>\$</u>	0.25	<u>\$</u>	0.25

See accompanying Notes to Consolidated Financial Statements.

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

Six Months Ended June 30, 2013 2012 (000's except per share amounts) Operating revenues: Electric \$ 255,788 243,817 Gas 28,270 21,487 Other 3,728 3,472 287,786 268,776 Operating revenue deductions: Fuel and purchased power 87,316 90.757 Cost of natural gas sold and transported 15.038 10.350 Regulated operating expenses 53.784 46.192 1,369 Other operating expenses 1,665 Maintenance and repairs 19,090 19,920 Loss on plant disallowance 2.409 Depreciation and amortization 33,736 30,003 Provision for income taxes 14,496 12,757 Other taxes 17,284 15,855 244,818 227,203 Operating income 42,968 41,573 Other income and (deductions): Allowance for equity funds used during construction 1,393 103 Interest income 517 302 Provision for other income taxes (35)(202)Other - non-operating expense, net (579)(429)1,296 (226)Interest charges: Long-term debt 20.141 20.292 Short-term debt 59 159 Allowance for borrowed funds used during construction (777)(167)Other 554 551 19,977 20,835 **Net income** 24.287 20.512 Weighted average number of common shares outstanding - basic 42,122 42,636 Weighted average number of common shares outstanding – diluted 42,652 42,143 **\$** 0.57 Total earnings per weighted average share of common stock -**\$ 0.49** basic and diluted

See accompanying Notes to Consolidated Financial Statements.

Dividends declared per share of common stock

\$ 0.50

0.50

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

Twelve Months Ended June 30,

		Julie	- 50,	
	-	2013		2012
	(00	0's except pe	r share	amounts)
Operating revenues:				
Electric	\$	522,624	\$	519,403
Gas		46,632		39,625
Other		6,851		6,797
		576,107		565,825
Operating revenue deductions:				
Fuel and purchased power		175,456		189,568
Cost of natural gas sold and transported		23,321		18,359
Regulated operating expenses		101,963		92,834
Other operating expenses		3,026		2,493
Maintenance and repairs		39,613		41,180
Loss on plant disallowance		2,409		-
Depreciation and amortization		64,180		59,318
Provision for income taxes		35,835		33,971
Other taxes		32,689		30,577
		478,492		468,300
Operating income		97,615		97,525
Other income and (deductions):		, , , ,		, , , ,
Allowance for equity funds used during construction		2,437		326
Interest income		1,187		819
Benefit/(provision) for other income taxes		105		(462)
Other - non-operating expense, net		(2,060)		(1,252)
outer men operating expenses, more	-	1,669		(569)
Interest charges:		.,		(/
Long-term debt		40,042		41,599
Short-term debt		87		199
Allowance for borrowed funds used during construction		(1,392)		(304)
Other		1,091		1,075
	-	39,828		42,569
Net income	\$	59,456	\$	54,387
Weighted average number of common shares outstanding – basic		42,512		42,042
Weighted average number of common shares outstanding – diluted		42,526		42,061
Total earnings per weighted average share of common stock – basic and diluted	<u>\$</u>	<u>1.40</u>	<u>\$</u>	1.29
Dividends declared per share of common stock	<u>\$</u>	<u> 1.00</u>	<u>\$</u>	0.50

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	<u>June 30, 2</u>	2013 <u>December 31, 20</u>	<u>012</u>
		(\$-000's)	
Assets			
Plant and property, at original cost:			
Electric	\$ 2,194,95	59 \$ 2,176,188	
Natural gas	71,23	84 69,851	
Other	38,74	18 37,983	
Construction work in progress	99,75	<u>56,347</u>	
	2,404,69	96 2,340,369	
Accumulated depreciation and amortization	704,53	682,737	
	1,700,16	1,657,632	
Current assets:			
Cash and cash equivalents	10,85	3,375	
Restricted cash	1,77	7 3 4,357	
Accounts receivable – trade, net of allowance \$1,889			
and \$945, respectively	46,03	38,874	
Accrued unbilled revenues	20,96	38 23,254	
Accounts receivable – other	19,65	52 13,277	
Fuel, materials and supplies	51,56		
Prepaid expenses and other	21,87	' 2 21,806	
Unrealized gain in fair value of derivative contracts	5	53 96	
Regulatory assets	6,47		
	179,24	<u>173,286</u>	
Noncurrent assets and deferred charges:			
Regulatory assets	234,49	96 243,958	
Goodwill	39,49	39,492	
Unamortized debt issuance costs	9,01	9 7,606	
Unrealized gain in fair value of derivative contracts	12	27 191	
Other	6,09		
	289,23		
Total Assets	<u>\$ 2,168,63</u>	<u>\$ 2,126,369</u>	
(Continued)			

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY CONSOLIDATED BALANCE SHEETS (UNAUDITED) (Continued)

	June 30, 2013	December 31, 2012
		000's)
Capitalization and Liabilities		
Common stock, \$1 par value, 42,830,673 and 42,484,363		
shares issued and outstanding, respectively	\$ 42,831	\$ 42,484
Capital in excess of par value	634,457	628,199
Retained earnings	50,070	<u>47,115</u>
Total common stockholders' equity	727,358	717,798
Long-term debt (net of current portion):		
Obligations under capital lease	4,306	4,441
First mortgage bonds and secured debt	637,559	487,541
Unsecured debt	<u>101,676</u>	199,644
Total long-term debt	743,541	691,626
Total long-term debt and common stockholders' equity	1,470,899	1,409,424
Current liabilities:		
Accounts payable and accrued liabilities	46,371	66,559
Current maturities of long-term debt	418	714
Short-term debt	-	24,000
Regulatory liabilities	5,003	5,470
Customer deposits	12,276	12,001
Interest accrued	6,748	5,902
Other current liabilities	1,369	-
Unrealized loss in fair value of derivative contracts	2,612	3,403
Taxes accrued	11,703	2,992
	86,500	121,041
Commitments and contingencies (Note 7)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	133,895	131,888
Deferred income taxes	312,871	301,967
Unamortized investment tax credits	18,629	18,897
Pension and other postretirement benefit obligations	122,604	120,808
Unrealized loss in fair value of derivative contracts	4,362	3,819
Other	18,877	18,525
	611,238	595,904
Total Capitalization and Liabilities	\$ 2,168,637	\$ 2,126,369

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

June 30. 2013 2012 (\$-000's) Operating activities: Net income \$ 24.287 \$ 20.512 Adjustments to reconcile net income to cash flows from operating activities: Depreciation and amortization including regulatory items 35.268 40.561 Pension and other postretirement benefit costs, net of contributions 7,174 1,187 Deferred income taxes and unamortized investment tax credit, net 12,096 13,496 Allowance for equity funds used during construction (1,393)(103)Stock compensation expense 1,900 1,404 Loss on plant disallowance 2,409 Regulatory reversal of gain on sale of assets 1,236 Non-cash (gain)/loss on derivatives (67)4 Other (16)Cash flows impacted by changes in: Accounts receivable and accrued unbilled revenues (7,140)(2.062)Fuel, materials and supplies 8.138 2.424 Prepaid expenses, other current assets and deferred charges 542 (2,602)Accounts payable and accrued liabilities (20.639)(16.084)Interest, taxes accrued and customer deposits 9,832 8,587 Other liabilities and other deferred credits <u>4,3</u>44 (2,638)Net cash provided by operating activities 71,005 71,652 Investing activities: Capital expenditures – regulated (74.834)(60,760)Capital expenditures and other investments – non-regulated (934)(1,504)Decrease in restricted cash 2,585 Net cash used in investing activities (73,183)(62, 264)Financing activities: Proceeds from first mortgage bonds, net 150.000 88.000 Long-term debt issuance costs (1,744)(974)Redemption of senior notes (98.000)Proceeds from issuance of common stock net of issuance costs 4,666 5,161 Repayment of first mortgage bonds (88,029)Net short-term borrowings/(repayments) (24,000)5,850 Dividends (21,332)(21,077)Other (432)(458)Net cash provided by/(used in) financing activities 9,653 (12,022)Net increase/(decrease) in cash and cash equivalents 7,475 (2,634)Cash and cash equivalents at beginning of period 3,375 5,408 Cash and cash equivalents at end of period 10,850 \$ 2,774

Six Months Ended

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 - Summary of Significant Accounting Policies

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly-owned subsidiary which provides natural gas distribution to customers in 48 communities in northwest, north central and west central Missouri. Our other segment consists of our fiber optics business.

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, 2012.

The information furnished reflects all adjustments, consisting only of normal recurring adjustments, which are in our opinion necessary to state 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, 2012, of which there were none.

Note 2 - Recently Issued and Proposed Accounting Standards

<u>Balance Sheet Offsetting:</u> The FASB amended the guidance governing the offsetting, or netting, of assets and liabilities on the balance sheet. Under the revised guidance, an entity is required to disclose both the gross and net information about instruments and transactions that are eligible for offset on the balance sheet, as well as instruments or transactions subject to a master netting agreement. This standard was effective for annual periods beginning after January 1, 2013. We implemented this standard in the first quarter of 2013 and it did not have a material impact on our results of operations, financial position or liquidity.

Note 3- Regulatory Matters

On February 27, 2013, the MPSC approved a joint settlement agreement for our 2012 Missouri rate case. The agreement provided for an annual increase in base revenues for our Missouri electric customers in the amount of approximately \$27.5 million, effective April 1, 2013, and the continuation of the current fuel adjustment mechanism. The agreement also included an increase in depreciation rates, recovery of deferred tornado costs over the next ten years and the continuation of tracking mechanisms for expenses related to employee pension, retiree health care, vegetation management, and latan 2, latan Common and Plum Point operating and maintenance costs. In addition, the agreement included a write-off of approximately \$3.6 million, consisting of a \$2.4 million disallowance for the prudency of certain construction expenditures for latan 2 and a \$1.2 million regulatory reversal of a prior period gain on sale of our Asbury unit train, which is included in regulated operating expenses. We also agreed not to implement a Missouri general rate increase prior to October 1, 2014.

The following table sets forth the components of our regulatory assets and liabilities on our consolidated balance sheet (in thousands).

Regulatory Assets and Liabilities

	<u>June 30, 2013</u>	December 31, 2012
Regulatory Assets:		
Current:		
Under recovered fuel costs ⁽¹⁾	\$ 401	\$ 2,885
Current portion of long-term regulatory assets ⁽¹⁾	6,077	<u>3,492</u>
Regulatory assets, current ⁽¹⁾	6,478	<u>6,377</u>
Long-term:		
Pension and other postretirement benefits ⁽²⁾	130,626	136,480
Income taxes	47,816	48,759
Deferred construction accounting costs ⁽³⁾	16,496	16,717
Unamortized loss on reacquired debt	11,415	12,142
Unsettled derivative losses – electric segment	6,372	6,557
System reliability – vegetation management	8,235	9,002
Storm costs ⁽⁴⁾	5,257	4,828
Asset retirement obligation	4,554	4,430
Customer programs	4,702	4,356
Unamortized loss on interest rate derivative	1,013	1,147
Other	980	669
Deferred operating and maintenance expense	2,288	2,049
Under recovered fuel costs	819	314
Current portion of long-term regulatory assets	(6,077)	(3,492)
Regulatory assets, long-term	234,496	243,958
Total Regulatory Assets	\$ 240,974	\$ 250,335
	June 30, 2013	December 31, 2012
Regulatory Liabilities:		
Current:		
Over recovered fuel costs	\$ 1,652	\$ 2,381
Current portion of long-term regulatory liabilities ⁽¹⁾	<u>3,351</u>	3,089
Regulatory liabilities, current ⁽¹⁾	5,003	5,470
Long-term:		
Costs of removal	90,278	83,368
SWPA payment for Ozark Beach lost generation	20,834	22,242
Income taxes	11,863	11,972
Deferred construction accounting costs – fuel	8,083	8,156
Unamortized gain on interest rate derivative	3,456	3,541
Pension and other postretirement benefits ⁽⁵⁾	1,323	2,007
Over recovered fuel costs	1,409	3,691
Current portion of long-term regulatory liabilities ⁽¹⁾	(3,351)	(3,089)
Regulatory liabilities, long-term	133,895	131,888
Total Regulatory Liabilities	<u>\$ 138,898</u>	\$ <u>137,358</u>

luna 20 2042

- (1) Reflects over and under recovered costs of the current portion of regulatory assets or liabilities detailed in the long term sections below expected to be returned or recovered, as applicable, within the next 12 months in rates.
- (2) Includes the effect of costs incurred that are more or less than those allowed in rates for Missouri (EDE and EDG) and Kansas (EDE) portion of pension and other postretirement benefit costs. Since January 1, 2013, regulatory assets have been reduced, and corresponding expenses have increased, as a result of ratemaking treatment.

(3) Balances as of June 30, 2013	Deferred Carrying Charges	Deferred O&M	Depreciation	<u>Total</u>
latan 1	\$2,637	\$1,319	\$1,598	\$ 5,554
latan 2	3,788	4,097	2,663	10,548
Plum Point	64	173	157	394
Total			_	\$ 16,496
Balances as of December 31, 2012	Deferred Carrying Charges	Deferred O&M	Depreciation	<u>Total</u>
Balances as of December 31, 2012 latan 1	<u>Deferred Carrying Charges</u> \$2,678	<u>Deferred O&M</u> \$1,339	Depreciation \$1,622	<u>Total</u> \$ 5,639
latan 1	\$2,678	\$1,339	\$1,622	\$ 5,639

(4) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado.

(5) Includes the effect of costs incurred that are more or less than those allowed in rates for the Missouri (EDE and EDG) and Kansas (EDE) portion of pension and other postretirement benefit costs. Since January 1, 2013, regulatory liabilities and corresponding expenses have been reduced as a result of ratemaking treatment.

Note 4- Risk Management and Derivative Financial Instruments

We engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into both physical and financial contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain predictability. We recognize that if risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All derivative instruments are recognized at fair value on the balance sheet with the unrealized losses or gains from derivatives used to hedge our fuel costs in our electric segment recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instrument in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our Consolidated Statement of Income and subject to our fuel adjustment clause.

As of June 30, 2013 and December 31, 2012, we have recorded the following assets and liabilities representing the fair value of derivative financial instruments, (in thousands):

ASSET DERIVATIVES			June 30, 2013		ember 31, 2012
Non-designated hedging					
instruments due to regulatory accounting	Balance Sheet Classification	Fa	ir Value	Fa	air Value
Natural gas contracts, gas segment	Current assets Non-current assets and deferred charges	\$	17	\$	3
	– Other		-		17
Natural gas contracts, electric segment	Current assets		36		93
-	Non-current assets and deferred charges		127		174
Total derivatives assets		\$	180	\$	287
LIABILI	ITY DERIVATIVES	J	une 30, 2013	Dec	ember 31, 2012
Non-designated as hedging instruments due to regulatory accounting					
Natural gas contracts, gas segment	Current liabilities	\$	10	\$	104
	Non-current liabilities and deferred credits		-		-
Natural gas contracts, electric segment	Current liabilities		2,602		3,299
	Non-current liabilities and deferred credits		4,362		3,819
Total derivatives liabilities		\$	6,974	\$	7,222

Electric

At June 30, 2013, approximately \$2.6 million of unrealized losses are applicable to financial instruments which will settle within the next twelve months.

The following tables set forth "mark-to-market" pre-tax gains/(losses) from non-designated derivative instruments for the electric segment for each of the periods ended June 30, (in thousands):

Non-Designated Hedging Instruments - Due to Regulatory Accounting	Balance Sheet Classification of Gain / (Loss) on	Amo	unt of Gain	/ (Loss) Re	cognized or	n Balance Sh	eet
Electric Segment	Derivatives	Three Mont	=	Six Month	=		nths Ended
Commodity contracts	Regulatory	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
	(assets)/liabilities	\$ (2,852)	<u>\$ 474</u>	\$ (432)	\$ (1,828)	\$ (1,052)	\$ (8,057)
Total Electric Segment		<u>\$ (2,852)</u>	<u>\$ 474</u>	<u>\$ (432)</u>	<u>\$ (1,828)</u>	<u>\$ (1,052)</u>	<u>\$ (8,057)</u>
Non-Designated Hedging Instruments - Due to Regulatory Accounting Electric Segment	Statement of Income Classification of Gain / (Loss) on	Amoun	t of Gain / (L	_oss) Reco	gnized in Ind	come on Der	rivative
·	Derivatives		nths Ended	•	ths Ended		nths Ended
Commodity contracts	Fuel and purchased	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
,	power expense	<u>\$ (407)</u>	<u>\$ 83</u>	<u>\$ (521)</u>	<u>\$ 59</u>	\$ (4,565)	\$ (1,781)
Total Electric Segment		<u>\$ (407)</u>	<u>\$ 83</u>	<u>\$ (521)</u>	<u>\$ 59</u>	<u>\$ (4,565)</u>	<u>\$ (1,781)</u>

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to fair value accounting because they qualify for the normal purchase normal sale exemption. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchase normal sale exception contain a price adjustment feature and will account for these contracts accordingly.

As of June 30, 2013, the following volumes and percentage of our anticipated volume of natural gas usage for our electric operations for the remainder of 2013 and for the next four years are shown below at the following average prices per Dekatherm (Dth).

		Dth Hedged		
<u>Year</u>	% Hedged	Physical	<u>Financial</u>	Average Price
Remainder 2013	64%	1,090,000	2,690,000	\$ 5.024
2014	39%	460,000	3,540,000	\$ 4.741
2015	31%	-	3,010,000	\$ 4.708
2016	21%	-	2,100,000	\$ 4.415
2017	10 %	-	1,050,000	\$ 4.430

We utilize the following procurement guidelines for our electric segment, allowing the flexibility to hedge up to 100% of the current year's and 80% of any future year's expected requirements while being cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty (including with respect to required volumes and counterparty credit) are also considered. These guidelines do not reflect any changes that might occur as a result of the implementation of the SPP Day-Ahead Market in 2014.

<u>Year</u>	Minimum % Hedged
Current	Up to 100%
First	60%
Second	40%
Third	20%
Fourth	10%

Gas

We attempt to mitigate our natural gas price risk for our gas segment by a combination of (1) injecting natural gas into storage during the off-heating season months, (2) purchasing physical

forward contracts and (3) purchasing financial derivative contracts. We target to have 95% of our storage capacity full by November 1 for the upcoming winter heating season. As the winter progresses, gas is withdrawn from storage to serve our customers. As of June 30, 2013, we had 0.8 million Dths in storage on the three pipelines that serve our customers. This represents 38% of our storage capacity.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the Actual Cost Adjustment (ACA) year at September 1 and illustrates our hedged position as of June 30, 2013 (in thousands).

	Minimum %	Dth Hedged	Dth Hedged		
<u>Season</u>	<u>Hedged</u>	<u>Financial</u>	Physical	Dth in Storage	Actual % Hedged
Current	50%	220,000	239,635	757,824	38%
Second	Up to 50%	-	-	-	-
Third	Up to 20%	_	-	-	-

A Purchased Gas Adjustment (PGA) clause is included in our rates for our gas segment operations, therefore, we mark to market any unrealized gains or losses and any realized gains or losses relating to financial derivative contracts to a regulatory asset or regulatory liability account on our balance sheet.

The following table sets forth "mark-to-market" pre-tax gains / (losses) from derivatives not designated as hedging instruments for the gas segment for each of the periods ended June 30, (in thousands).

Non-Designated Hedging Instruments Due to Regulatory	Balance Sheet Classification of	Amount of Gain/(Loss) Recognized on Balance Sheet						
Accounting - Gas Segment	Gain / (Loss) on Derivative	Three Months Ended		Six Months Ended		Twelve Months Ended		
O	D. Litter	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	
Commodity contracts	Regulatory (assets)/liabilities	<u>\$ (71)</u>	<u>\$ 164</u>	<u>\$ (18)</u>	<u>\$ (491)</u>	<u>\$ 12</u>	<u>\$ (2,136)</u>	
Total - Gas Segment		<u>\$ (71)</u>	<u>\$ 164</u>	<u>\$ (18)</u>	<u>\$ (491)</u>	<u>\$ 12</u>	<u>\$ (2,136)</u>	

Contingent Features

Certain of our derivative instruments contain provisions that require our senior unsecured debt to maintain an investment grade credit rating with any relevant credit rating agency. If our debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request increased collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with the credit-risk-related contingent features that are in a liability position on June 30, 2013 is \$2.1 million for which we have posted no collateral in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered on June 30, 2013, we would have been required to post \$2.1 million of collateral with one of our counterparties. In addition, certain counterparties make available collateral in the form of cash held as margin deposits as a result of exceeding agreed-upon credit exposure thresholds or may be required to prepay the transaction. Conversely, we are required to post collateral with counterparties at certain thresholds, which is typically the result of changes in commodity prices. Amounts reported as margin deposit liabilities represent counterparty funds we hold that result from various trading counterparties exceeding agreed-upon credit exposure thresholds. Amounts reported as margin deposit assets represent our funds held on deposit for our NYMEX contracts with our broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at June 30, 2013 and December 31, 2012. There were no margin deposit liabilities at these dates.

	June 30, 2013	December 31, 2012
(in millions) Margin deposit assets	\$ 5.0	\$ 4.2

Offsetting of derivative assets and liabilities

We believe that entering into master trading and netting agreements mitigates the level of financial loss that could result from a default under derivatives agreements by allowing net settlement of derivative assets and liabilities. We generally enter into the following master trading and netting agreements: (1) the International Swaps and Derivatives Association Agreement, a standardized financial natural gas and electric contract; and (2) the North American Energy Standards Board Inc. Agreement, a standardized contract for the purchase and sale of natural gas. These master trading and netting agreements allow the counterparties to net settle sale and purchase transactions. Further, collateral requirements are calculated at the master trading and netting agreement level by the counterparty.

As shown above, our asset and liability commodity contract derivatives are reported at gross on the balance sheet. Accounting Standards Codification (ASC) guidance permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a liability) against fair value amounts recognized for derivative instruments that are executed with the same counterparty under the same master netting arrangement. For the periods ended June 30, 2013 and December 31, 2012, we did not hold any collateral posted by our counterparties. The only collateral we have posted is our margin deposit assets described above. We have elected not to offset our margin deposit assets against any of our eligible commodity contracts.

Note 5– Fair Value Measurements

The accounting guidance on fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: (i) Level 1, defined as quoted prices in active markets for identical instruments; (ii) Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and (iii) Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Our Level 2 fair value measurements consist of both quoted price inputs and inputs that are derived principally from or corroborated by observable market data.

The guidance also requires that the fair value measurements of assets and liabilities reflect the nonperformance risk of counterparties and the reporting entity, as applicable. Therefore, using credit default spreads, we factored the impact of our own credit standing and the credit standing of our counterparties, as well as any potential credit enhancements (e.g. collateral) into the consideration of nonperformance risk for both derivative assets and liabilities. The results of this analysis were not material to the financial statements.

The following fair value hierarchy table presents information about our assets measured at fair value using the market value approach on a recurring basis as of June 30, 2013 and December 31, 2012.

		Fair	Fair Value Measurements at Reporting Date Using								
(\$ in 000's)		Quoted Prices in			Significant Other		Significant				
<u>Description</u>	Assets/(Liabilities) <u>at Fair Value</u>		Active Markets for Identical Liabilities (Level 1)		Observable Inputs <u>(Level 2)</u>		Unobservable Inputs (<u>Level 3)</u>				
				June 30, 2013							
Derivative assets	\$	180	\$	180							
Derivative liabilities	\$	(6,974)	\$	(6,974)	\$	-	\$	-			
				December 31, 201	<u>2</u>						
Derivative assets	\$	287	\$	287	\$	-	\$	-			
Derivative liabilities	\$	(7,222)	\$	(7,222)	\$	-	\$	_			

Our cash and cash equivalents approximate fair value because of the short-term nature of these instruments, and are classified as Level 1 in the fair value hierarchy. The carrying amount of our short-term debt, which is composed of Empire issued commercial paper or revolving credit

borrowings, also approximates fair value because of their short-term nature. These instruments are classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar market transactions. The carrying amount of our total long-term debt exclusive of capital leases at June 30, 2013, was \$739.4 million as compared to \$687.6 at December 31, 2012. The fair market value at June 30, 2013 was approximately \$725.0 million as compared to \$747.2 at December 31, 2012. These estimates were based on a bond pricing model, utilizing inputs classified as Level 2 in the fair value hierarchy, which include the quoted market prices for the same or similar issues or on the current rates offered to us for debt of the same remaining maturities. The estimated fair market value may not represent the actual value that could have been realized as of June 30, 2013 or that will be realizable in the future.

Note 6- Financing

On October 30, 2012, we entered into a Bond Purchase Agreement for a private placement of \$30.0 million of 3.73% First Mortgage Bonds due May 30, 2033 and \$120.0 million of 4.32% First Mortgage Bonds due May 30, 2043. The delayed settlement of both series of bonds occurred on May 30, 2013. Interest is payable semi-annually on the bonds on each May 30 and November 30, commencing November 30, 2013. The bonds may be redeemed at our option, at any time prior to maturity, at par plus a make whole premium, together with accrued and unpaid interest, if any, to the redemption date. The bonds have not been registered under the Securities Act of 1933, as amended. The bonds were issued under the EDE Mortgage. The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to \$1 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage.

We used a portion of the proceeds from the sale of these bonds to redeem all \$98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013. The remaining proceeds will be used for general corporate purposes.

We have an unsecured revolving credit facility of \$150 million in place through January 17, 2017. The facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness 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 and amortization) to be at least two times our interest charges 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. As of June 30, 2013, we are in compliance with these ratios. Our total indebtedness is 50.6% of our total capitalization as of June 30, 2013 and our EBITDA is 5.0 times our interest charges. This credit facility is also subject to cross-default if we default on in excess of \$10 million in the aggregate on our other indebtedness. This arrangement does not serve to legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under this agreement and no outstanding commercial paper at June 30, 2013.

Note 7– Commitments and Contingencies

Legal Proceedings

We are a party to various claims and legal proceedings arising out of the normal course of our business. Management regularly analyzes this information, and has provided accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of management, it is not probable, given the company's defenses, that the ultimate outcome of these claims and lawsuits will have a material adverse effect upon our financial condition, or results of operations or cash flows.

A lawsuit was filed in Jasper County Circuit Court (the Court) against us by three of our residential customers, purporting to act on behalf of all Empire customers. These customers were seeking a refund of certain amounts paid for service provided by Empire between January 1, 2007,

and December 13, 2007. At all times, we charged the three plaintiffs, and all of our customers, the rates approved by and on file with the MPSC from our 2006 rate case. While the precise circumstances of Empire's 2006 rate case and the approval of Empire's tariffs have not previously been addressed by Missouri's appellate courts, we believe that case law supports the position that the MPSC may not re-determine rates already established and paid without depriving the utility, or a consumer if the rates were originally too low, of its property without due process.

We filed a motion asking the Court to dismiss the case on the basis that the plaintiffs had not stated a valid claim. A hearing on our motion was held April 18, 2012. The Court granted Empire's motion to dismiss, and a judgment was issued by the Court on June 29, 2012, dismissing the case. The plaintiffs filed a Notice of Appeal on July 30, 2012. The Missouri Court of Appeals for the Southern District dismissed the case for failure to properly perfect the appeal. The plaintiffs moved to set aside the dismissal, and the Court of Appeals restored the case to its active docket. On June 18, 2013, the Court of Appeals affirmed the dismissal with prejudice by the Jasper County Circuit Court based on our argument that a court could not re-determine what rate Empire should have charged other than the rate on file. The plaintiffs filed a motion with the Court of Appeals seeking reconsideration of the decision or transfer to the Missouri Supreme Court. The Court of Appeals denied the motion. On July 24, 2013, the plaintiffs filed a notice with the Court of Appeals stating that the plaintiffs intend to file an Application to Transfer with the Missouri Supreme Court.

Coal, Natural Gas and Transportation Contracts

The following table sets forth our firm physical gas, coal and transportation contracts for the periods indicated as of June 30, 2013 (in millions).

	Firm physical gas and transportation contracts	Coal and coal transportation contracts		
July 1, 2013 through December 31, 2013	\$ 18.7	\$ 10.4		
January 1, 2014 through December 31, 2015	30.5	32.3		
January 1, 2016 through December 31, 2017	22.2	22.8		
January 1, 2018 and beyond	8.3	22.8		

In addition to the above, we have an agreement with Southern Star Central Pipeline, Inc. to purchase one million Dths of firm gas storage service capacity for our electric business for a period of five years, expiring April 2016. The reservation charge for this storage capacity is approximately \$1.1 million annually.

We have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and natural gas operations. Under these contracts, the natural gas supplies are divided into firm physical commitments and derivatives that are used to hedge future purchases. In the event that this gas cannot be used at our plants, the gas would be liquidated at market price. The firm physical gas and transportation commitments are detailed in the table above.

We have coal supply agreements and transportation contracts in place to provide for the delivery of coal to the plants. These contracts are written with Force Majeure clauses that enable us to reduce tonnages or cease shipments under certain circumstances or events. These include mechanical or electrical maintenance items, acts of God, war or insurrection, strikes, weather and other disrupting events. This reduces the risk we have for not taking the minimum requirements of fuel under the contracts. The minimum requirements for our coal and coal transportation contracts as of June 30, 2013, are detailed in the table above.

Purchased Power

We currently supplement our on-system generating capacity with purchases of capacity and energy from other entities in order to meet the demands of our customers and the capacity margins applicable to us under current pooling agreements and National Electric Reliability Council (NERC) rules.

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the unit's capacity. We also have a long-term (30 year) agreement for the purchase of capacity from Plum Point. We began receiving purchased power under this agreement on September 1, 2010. We have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. We evaluated this purchase option as part of our Integrated Resource Plan (IRP), which was filed with the MPSC on July 1, 2013. While it is not currently our intention to exercise this option in 2015, we will continue to evaluate this purchase option through the exercise date as well as explore other options with the purchase power agreement holder, Plum Point Energy Associates (PPEA), related to the timing of this option. Commitments under this agreement are approximately \$301.9 million through August 31, 2039, the end date of the agreement.

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC (formerly Horizon Wind Energy), Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately \$14.6 million based on a 20-year average cost. We also have a 20-year contract, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately \$16.9 million based on a 20-year average cost. Although these agreements are considered operating leases under Generally Accepted Accounting Principles (GAAP), payments for these wind agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in our operating lease obligations. We do not own any portion of these windfarms.

New Construction

On July 9, 2013, we signed a contract with a third party vendor to complete engineering, procurement, and construction activities at our Riverton plant to convert Riverton Unit 12 from a simple cycle combustion turbine to a combined cycle unit. The conversion will include the installation of a heat recovery steam generator (HRSG), steam turbine generator, auxiliary boiler, cooling tower, and other auxiliary equipment. The Air Emission Source Construction Permit necessary for this project was issued by Kansas Department of Health and Environment on July 11, 2013. See "Environmental Matters" below for additional information about this project and associated compliance measures.

On January 16, 2012, we signed a contract with a third party vendor to complete environmental retrofits at our Asbury plant. The retrofits include the installation of a pulse-jet fabric filter (baghouse), circulating dry scrubber and powder activated carbon injection system. This equipment will enable us to comply with the Mercury and Air Toxics Standard (MATS). See "Environmental Matters" below for more information and for project costs.

Leases

We have purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC, which are considered operating leases for GAAP purposes. Details of these agreements are disclosed in the Purchased Power section of this note.

We also currently have short-term operating leases for two unit trains to meet coal delivery demands, for garage and office facilities for our electric segment and for one office facility related to our gas segment. In addition, we have capital leases for certain office equipment and 108 railcars to provide coal delivery for our ownership and purchased power agreement shares of the Plum Point generating facility.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. We expect this trend to continue. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect any such costs to be material, although recoverable in rates.

Electric Segment

<u>Air</u>

The Federal Clean Air Act (CAA) and comparable state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for sulfur dioxide (SO2), particulate matter, nitrogen oxides (NOx) and mercury. In the future they are also likely to include limits on other hazardous pollutants (HAPs) and greenhouse gases (GHG) such as carbon dioxide (CO_2) and methane.

Permits

Under the CAA we have obtained, and renewed as necessary, site operating permits, which are valid for five years, for each of our plants. As stated above, on July 11, 2013, we received the Air Emission Source Construction Permit necessary to begin construction on the Riverton 12 Combined Cycle Conversion project.

Compliance Plan

In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). While the Cross State Air Pollution Rule (CSAPR - formerly the Clean Air Transport Rule, or CATR) that was set to take effect on January 1, 2012 was stayed in late December 2011 then vacated in August 2012 by the District of Columbia Circuit Court of Appeals, the Mercury Air Toxics Standard (MATS) was signed by the Environmental Protection Agency (EPA) Administrator on December 16, 2011 and became effective on April 16, 2012. MATS requires compliance by April 2015 (with flexibility for extensions for reliability reasons). Our Compliance Plan largely follows the preferred plan presented in our 2010 Integrated Resource Plan (IRP) and is further supported by our recent IRP filing. As described above under New Construction, we have begun the installation of a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant. The addition of this air quality control equipment is expected to be completed by early 2015 at a cost ranging from \$112.0 million to \$130.0 million, excluding AFUDC. Construction costs through June 30, 2013 were \$28.6 million for 2013 and \$58.9 million for the project to date, excluding AFUDC. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, a steam turbine currently rated at 14 megawatts that is used for peaking purposes.

In September 2012, we completed the transition of our Riverton Units 7 and 8 from operation on coal to operating completely on natural gas. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 or 8 for start-up, will be retired upon the conversion of Riverton Unit 12, a simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled to be completed in 2016 at a cost estimated to range from \$165 million to \$175 million, excluding AFUDC. This is approximately \$35 million higher than the amount included in our five-year capital expenditure plan disclosed in our 2012 10-K. Construction costs, consisting of pre-engineering and site preparation activities thus far, through June 30, 2013 were \$1.1 million for 2013 and \$1.9 million for the project to date, excluding AFUDC. An update to the

Company's overall capital expenditure estimates for 2014-2018 will be provided as part of our September 30, 2013 10-Q filing.

SO2 Emissions

The CAA regulates the amount of SO2 an affected unit can emit. Currently SO2 emissions are regulated by the Title IV Acid Rain Program and the Clean Air Interstate Rule (CAIR). On January 1, 2012, CAIR was to have been replaced by the Cross-State Air Pollution Rule (CSAPR). But, as discussed above, CSAPR was subsequently vacated, and CAIR will remain in effect until the EPA develops a valid replacement.

On October 5, 2012, the Department of Justice, on behalf of the EPA, requested that the Court of Appeals grant a request for a re-hearing of CSAPR. On January 24, 2013, the request was denied by the Court of Appeals and on March 29, 2013, the EPA petitioned the United States Supreme Court (the Supreme Court) to review the D.C. Circuit Court's decision. On June 24, 2013 the Supreme Court agreed to review the D.C. Circuit court's decision which is anticipated to occur in June 2014. In the meantime, both the Title IV Acid Rain Program and CAIR will remain in effect.

The Mercury Air Toxics Standards (MATS), discussed further below, was signed on December 16, 2011, and will affect SO2 emission rates at our facilities. In addition, the compliance date for the revised SO2 National Ambient Air Quality Standards (NAAQS) is August of 2017; this will also affect SO2 emissions at our facilities. The SO2 NAAQS is discussed in more detail below.

Title IV Acid Rain Program:

Under the Title IV Acid Rain Program, each existing affected unit has been allocated a specific number of emission allowances by the U.S. Environmental Protection Agency (EPA). Each allowance entitles the holder to emit one ton of SO2. Covered utilities, such as Empire, must have emission allowances equal to the number of tons of SO2 emitted during a given year by each of their affected units. Allowances in excess of the annual emissions are banked for future use. In 2012, our SO2 emissions exceeded the annual allocations. This deficit was covered by our banked allowances. We estimate our Title IV Acid Rain Program SO2 allowance bank plus annual allocations will be more than our projected emissions through 2017. Long-term compliance with this program will be met by the Compliance Plan detailed above along with possible procurement of additional SO2 allowances. We expect the cost of compliance to be fully recoverable in our rates.

CAIR:

In 2005, the EPA promulgated CAIR under the CAA. CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO2 and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where our Asbury, Energy Center, State Line and latan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and our Riverton Plant was not affected. Arkansas, where our Plum Point Plant is located, was included for ozone season NOx but not for SO2.

In 2008, the U.S. Court of Appeals for the District of Columbia vacated CAIR and remanded it back to EPA for further consideration, but also stayed its vacatur. As a result, CAIR became effective for NOx on January 1, 2009 and for SO2 on January 1, 2010 and required covered states to develop State Implementation Plans (SIPs) to comply with specific SO2 state-wide annual budgets.

SO2 allowance allocations under the Title IV Acid Rain Program are used for compliance in the CAIR SO2 Program. Beginning in 2010, SO2 allowances were utilized at a 2:1 ratio for our Missouri units. As a result, based on current SO2 allowance usage projections, we expected to have sufficient allowances to take us through 2017.

In order to meet CAIR requirements for SO2 and NOx emissions (NOx is discussed below in more detail) and as a requirement for the air permit for latan 2, a Selective Catalytic Reduction system (SCR), a Flue-Gas Desulfurization (FGD) scrubber system and baghouse were installed at our jointly-owned latan 1 plant and a SCR was placed in service at our Asbury plant in 2008. Our jointly-owned latan 2 and Plum Point plants were originally constructed with the above technology.

CSAPR- formerly the Clean Air Transport Rule:

On July 6, 2010, the EPA published a proposed CAIR replacement rule entitled the Clean Air Transport Rule (CATR). As proposed and supplemented, the CATR included Missouri and Kansas under both the annual and ozone season for NOx as well as the SO2 program while Arkansas remained in the ozone season NOx program only. The final CATR was released on July 7, 2011 under the name of the CSAPR, and was set to become effective January 1, 2012. However, as mentioned above, the District of Columbia Circuit Court of Appeals vacated CSAPR on August 21, 2012, and the EPA has subsequently petitioned the Supreme Court to review the D.C. Circuit Court's decision. On June 24, 2013 the Supreme Court agreed to review the D.C. Circuit court's decision during its next term, which begins in October 2013. The CAIR will be in effect until a valid replacement is developed by the EPA.

When it was published, the final CSAPR required a 73% reduction in SO2 from 2005 levels by 2014. The SO2 allowances allocated under the EPA's Title IV Acid Rain Program could not be used for compliance with CSAPR but would continue to be used for compliance with the Title IV Acid Rain Program. Therefore, new SO2 allowances would be allocated under CSAPR and retired at one allowance per ton of SO2 emissions emitted. Based on current projections, we would receive more SO2 allowances than would be emitted. Long-term compliance with this Rule will be met by the Compliance Plan detailed above along with possible procurement of additional SO2 allowances. We anticipate compliance costs associated with CAIR or its subsequent replacement to be recoverable in our rates.

Mercury Air Toxics Standard (MATS):

The MATS standard was fully implemented and effective as of April 16, 2012, thus requiring compliance by April 16, 2015 (with flexibility for extensions for reliability reasons). The MATS regulation does not include allowance mechanisms. Rather, it establishes alternative standards for certain pollutants, including SO2 (as a surrogate for hydrogen chloride (HCI)), which must be met to show compliance with hazardous air pollutant limits (see additional discussion in the MATS section below).

SO2 National Ambient Air Quality Standard (NAAQS):

In June 2010, the EPA finalized a new 1-hour SO2 NAAQS which, for areas with no ambient SO2 monitor, originally required modeling to determine attainment and non-attainment areas within each state. In April 2012, the EPA announced that it is reconsidering this approach. The modeling of emission sources was to have been completed by June 2013 with compliance with the SO2 NAAQS required by August 2017. Because the EPA is reconsidering the compliance determination approach for areas without ambient SO2 monitors, the compliance time-frame may be pushed back. Draft guidance for 1-hour SO2 NAAQS has been published by the EPA to assist states as they prepare their SIP submissions. The EPA is also planning a rulemaking to address some of the 1-hour SO2 NAAQS implementation program elements. It is likely that coal-fired generating units will need scrubbers to be capable of meeting the new 1-hour SO2 NAAQS. In addition, units will be required to include SO2 emissions limits in their Title V permits or execute consent decrees to assure attainment and future compliance.

NOx Emissions

The CAA regulates the amount of NOx an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx limits. Currently, revised NOx emissions are limited by the CAIR as a result of the vacated CSPAR rule and by ozone NAAQS rules (discussed below) which were established in 1997 and in 2008.

CAIR:

The CAIR required covered states to develop SIPs to comply with specific annual NOx statewide allowance allocation budgets. Based on existing SIPs, we had excess NOx allowances during

2012 which were banked for future use and will be sufficient for compliance at least through the end of 2017. The CAIR NOx program also was to have been replaced by the CSAPR program January 1, 2012 but because the Court vacated CSAPR, CAIR will remain in effect until the EPA develops a valid replacement.

CSAPR:

As published, the CSAPR would have required a 54% reduction in NOx from 2005 levels by 2014. The NOx annual and ozone season allowances that were allocated and banked under CAIR could not be used for compliance under CSAPR. New allowances would have been issued under CSAPR. However, as discussed above, CSPAR was vacated by the District of Columbia Circuit Court of Appeals on August 21, 2012 and the EPA subsequently petitioned the Supreme Court to review the D.C. Circuit Court's decision. As previously mentioned, the Supreme Court agreed to review the case.

Ozone NAAQS:

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. On January 6, 2010, to protect public health, the EPA proposed to lower the primary NAAQS for ozone to a range between 60 and 70 ppb and to set a separate secondary NAAQS for ozone to protect sensitive vegetation and ecosystems.

On September 2, 2011, President Obama ordered the EPA to withdraw proposed air quality standards lowering the 2008 ozone standard pending the CAA 2013 scheduled reconsideration of the ozone NAAQS (the normal 5 year reconsideration period). States will move forward with area designations based on the 2008 75 ppb standard using 2008-2010 quality assured monitoring data. Our service territory will be designated as attainment, meaning it will be in compliance with the standard. In the interim, the 1997 ozone NAAQS will remain in effect.

PM NAAQS:

Particulate matter (PM) is the term for particles found in the air which comes from a variety of sources. On January 15, 2013, the EPA finalized the PM 2.5 primary annual standard at 12 ug/m³ (micrograms per cubic meter of air). States are required to meet the primary standard in 2020.

The standard should have no impact on our existing generating fleet because the PM 2.5 ambient monitor results are below the required level. However, the proposed standards could impact future major modifications/construction projects that require a Prevention of Significant Deterioration (PSD) permit.

Mercury Air Toxics Standard (MATS)

In 2005, the EPA issued the Clean Air Mercury Rule (CAMR) under the CAA. It set limits on mercury emissions by power plants and created a market-based cap and trade system expected to reduce nationwide mercury emissions in two phases. New mercury emission limits for Phase 1 were to go into effect January 1, 2010. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia vacated CAMR. This decision was appealed to the U.S. Supreme Court which denied the appeal on February 23, 2009.

The EPA issued Information Collection Requests (ICR) for determining the National Emission Standards for Hazardous Air Pollutants (NESHAP), including mercury, for coal and oil-fired electric steam generating units on December 24, 2009. The ICRs included our latan, Asbury and Riverton plants. All responses to the ICRs were submitted as required. The EPA ICRs were intended for use in developing regulations under Section 112(r) of the CAA maximum achievable emission standards for the control of the emission of hazardous air pollutants (HAPs), including mercury. The EPA proposed the national mercury and air toxics standards (MATS) in March 2011, which became effective April 16, 2012. MATS establishes numerical emission limits to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including HCl and hydrogen fluoride (HF). For all existing and new coal-fired electric utility steam generating units (EGUs), the proposed

standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply. On March 28, 2013, the EPA finalized updates to certain emission limits for new power plants under the MATS. The new standards affect only new coal and oil-fired power plants that will be built in the future. The update does not change the final emission limits or other requirements for existing power plants.

The MATS regulation of HAPs in combination with CSAPR is the driving regulation behind our Compliance Plan and its implementation schedule. We expect compliance costs to be recoverable in our rates.

Greenhouse Gases

Our coal and gas plants, vehicles and other facilities, including EDG (our gas segment), emit CO2 and/or other Greenhouse Gases (GHGs) which are measured in Carbon Dioxide Equivalents (CO2e).

On September 22, 2009, the EPA issued the final Mandatory Reporting of Greenhouse Gases Rule under the CAA which requires power generating and certain other facilities that equal or exceed an emission threshold of 25,000 metric tons of CO2e to report GHGs to the EPA annually commencing in September 2011. EDE and EDG's GHG emissions for 2011 and 2012 have been reported as required to the EPA.

On December 7, 2009, responding to a 2007 U.S. Supreme Court decision that determined that GHGs constitute "air pollutants" under the CAA, the EPA issued its final finding that GHGs threaten both the public health and the public welfare. This "endangerment" finding did not itself trigger any EPA regulations, but was a necessary predicate for the EPA to proceed with regulations to control GHGs. Since that time, a series of rules including the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) have been issued by the EPA. Several parties have filed petitions with the EPA and lawsuits have been filed challenging these rules. On June 26, 2012, the D.C. Circuit Court issued its opinion in the principal litigation of the EPA GHG rules (Endangerment, the Tailoring Rule, GHG emission standards for light-duty vehicles, and the EPA's rule on reconsideration of the PSD Interpretive Memorandum). The three-judge panel upheld the EPA's interpretation of the Clean Air Act provisions as unambiguously correct. This opinion solidifies the EPA's position that the CAA requires PSD and Title V permits for major emitters of greenhouse gases, such as Empire. Our ongoing projects are currently being evaluated for the projected increase or decrease of CO2e emissions as required by the Tailoring Rule.

As the result of an agreement to settle litigation pending in the U.S. Court of Appeals, on March 27, 2012, the EPA proposed a Carbon Pollution Standard for new power plants. This action is designed to limit the amount of carbon emitted by electric utility generating units. The New Source Performance Standard would require all new power plants to meet a CO2 emissions limit of 1,000 pounds per megawatt hour. This is equal to a coal-fired power plant capturing 50% or more of its emissions. The rule does offer some flexibility but would still require an average of 1,000 pounds per megawatt hour over a 30-year period. It is expected that most new natural gas-fired combined cycle units will meet the new standard. The proposed rule would apply only to new fossil-fuel-fired electric utility generating units. The proposal would not apply to existing units including modifications such as those required to meet other air pollution standards which are currently being undertaken at our Asbury facility.

In a June 25, 2013 memorandum to the EPA Administrator, President Obama directed the EPA to issue new proposed Carbon Pollution Standards for Future Power Plants by September 20, 2013 in light of the more than 2 million comments received on its initial proposed regulation. We will determine the impact, if any, on the Riverton Unit 12 conversion after the proposed rule is released. At this time, we do not expect the Riverton 12 combined cycle permit to be affected. Further, President Obama's memorandum to the EPA Administrator requested the EPA issue proposed carbon pollution standards, regulations, or guidelines for modified, reconstructed, and existing power plants by no later than June 1, 2014; issue final standards, regulations, or guidelines, for modified, reconstructed, and existing power plants by no later than June 1, 2015; and include in the guidelines addressing existing power plants a requirement that states submit to the EPA implementation plans by no later than June 30, 2016.

In addition, a variety of proposals have been and are likely to continue to be considered by Congress to reduce GHGs. Proposals are also being considered in the House and Senate that would delay, limit or eliminate the EPA's authority to regulate GHGs. At this time, it is not possible to predict what legislation, if any, will ultimately emerge from Congress regarding control of GHGs.

Certain states have taken steps to develop cap and trade programs and/or other regulatory systems which may be more stringent than federal requirements. For example, Kansas is a participating member of the Midwestern Greenhouse Gas Reduction Accord (MGGRA), one purpose of which is to develop a market-based cap and trade mechanism to reduce GHG emissions. The MGGRA has announced, however, that it will not issue a CO2e regulatory system pending federal legislative developments. Missouri is not a participant in the MGGRA.

The ultimate cost of any GHG regulations cannot be determined at this time. However, we expect the cost of complying with any such regulations to be recoverable in our rates.

Water Discharges

We operate under the Kansas and Missouri Water Pollution Plans that were implemented in response to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received necessary discharge permits.

The Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. The regulations became final on February 16, 2004. In accordance with these regulations, we submitted sampling and summary reports to the Kansas Department of Health and Environment (KDHE) which indicate that the effect of the cooling water intake structure on Empire Lake's aquatic life is insignificant. KCP&L, who operates Iatan Unit 1, submitted the appropriate sampling and summary reports to the Missouri Department of Natural Resources (MDNR).

In 2007 the United States Court of Appeals for the Second Circuit remanded key sections of these CWA regulations to the EPA. As a result, the EPA suspended the regulations and revised and signed a pre-publication proposed regulation on March 28, 2011. The EPA has secured an additional year to finalize the standards for cooling water intake structures under a modified settlement agreement. Following a recent court approved delay, the EPA is now obligated to finalize the rule by November 4, 2013. We will not know the full impact of these rules until they are finalized. If adopted in their present form, we expect regulations of Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) to have a limited impact at Riverton. The retirement of units 7 and 8 is scheduled in 2016. A new intake structure design and cooling tower will be constructed as part of the Unit 12 conversion at Riverton. Impacts at latan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Our new latan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally impacted by the final rule.

Surface Impoundments

We own and maintain coal ash impoundments located at our Riverton and Asbury Power Plants. Additionally, we own a 12% interest in a coal ash impoundment at the latan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. On April 19, 2013, the EPA signed a notice of proposed rulemaking to revise its wastewater effluent limitation guidelines and standards under the CWA for coal-fired power plants. The proposal calls for updates to operating permits beginning in July 2017. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs that might result from any new standards. All of our coal ash impoundments are compliant with existing state and federal regulations.

On June 21, 2010, the EPA proposed a new regulation pursuant to the Federal Resource Conservation and Recovery Act (RCRA) governing the management and storage of Coal Combustion

Residuals (CCR). In the proposal, the EPA presents two options: (1) regulation of CCR under RCRA subtitle C as a hazardous waste and (2) regulation of CCR under RCRA subtitle D as a non-hazardous waste. The public comment period closed in November 2010. It is anticipated that the final regulation will be published in 2014. We expect compliance with either option as proposed to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to \$15 million at our Asbury and Riverton Power Plants. This preliminary estimate will likely change based on the final CCR rule and its requirements. We expect resulting costs to be recoverable in our rates.

On September 23, 2010 and on November 4, 2010 EPA consultants conducted on-site inspections of our Riverton and Asbury coal ash impoundments, respectively. The consultants performed a visual inspection of the impoundments to assess the structural integrity of the berms surrounding the impoundments, requested documentation related to construction of the impoundments, and reviewed recently completed engineering evaluations of the impoundments and their structural integrity. In response to the inspection comments, the recommended geotechnical studies have been completed and new flow monitoring devices and settlement monuments at both coal ash impoundments have been installed. As a result of the transition from coal to natural gas, initial planning for the closure of the Riverton impoundment is in progress in coordination with the KDHE Bureau of Waste Management. We expect to close it in 2014. The final design for additional recommendations that will improve safety for slope stability at the Asbury impoundment is under review. We have received preliminary approval by the MDNR for the site permitting of a new utility waste landfill adjacent to the Asbury plant. Additionally, the work plan for the detailed site investigation (DSI) to include geologic and hydrologic investigations has been approved by the MDNR Division of Geology and Land Survey. Construction of the new landfill is expected in 2016.

Renewable Energy

As previously discussed, we have purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas and Elk River Windfarm, LLC, located in Butler County, Kansas. We do not own any portion of either windfarm. More than 15% of the energy we put into the grid comes from these long-term Purchased Power Agreements (PPAs). Through these PPAs, we generate about 900,000 renewable energy certificates (RECs) each year. A REC represents one megawatt-hour of renewable energy that has been delivered into the bulk power grid and "unbundles" the renewable attributes from the associated energy. This unbundling is important because it cannot be determined where the renewable energy is ultimately delivered once it enters the bulk power grid. As a result, RECs provide an avenue for renewable energy tracking and compliance purposes.

Missouri regulations currently require us and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase RECs, at the rate of at least 2% of retail sales in 2012, increasing to at least 15% by 2021. We are currently in compliance with this regulatory requirement. The regulations require that 2% of the renewable energy source must be solar; however, we believe we are exempted from the solar requirement. A challenge to our exemption, brought by two of our customers and Power Source Solar, Inc., was dismissed on May 31, 2011 by the Missouri Western District Court of Appeals. The plaintiffs filed in the Missouri Supreme Court for transfer of the case from the Missouri Western District to the Missouri Supreme Court. The transfer was denied. On January 30, 2013, a complaint was filed with the MPSC by Renew Missouri and others regarding several points of our 2011 RES Compliance Report and the 2012-2014 Compliance Plan. The complaint is currently under consideration by the MPSC.

Renewable energy standard compliance rules were published by the MPSC on July 7, 2010. Missouri investor-owned utilities and others initiated litigation to challenge these rules. On June 30, 2011, a Cole County Circuit Court judge ruled that portions of the MPSC rules were unlawful and unreasonable, in conflict with Missouri statute and in violation of the Missouri Constitution. Subsequent to that decision, a portion of the appeal was dropped and the entire order was stayed. On December 27, 2011 the judge issued another order identical to the one that was stayed except that the rulings with regard to the constitutionality issue had been omitted. The MPSC appealed this decision and in November of 2012 the court dismissed lawsuits brought against the RES and affirmed

the MPSC rules that were finalized in July 2010. Kansas established a renewable portfolio standard (RPS), effective November 19, 2010. It requires 10% of our Kansas retail customer peak capacity requirements to be sourced from renewables in 2012, increasing to 15% by 2016, and 20% by 2020. In addition, there are several proposals currently before the U.S. Congress to adopt a nationwide RPS.

We have been selling the majority of our RECs and plan to continue to sell all or a portion of them in the future. As a result of these REC sales, we cannot claim the underlying energy is renewable. Once a REC has been claimed or retired, it cannot be used for any other purpose. At the end of 2012, sufficient RECs, including hydro, were retired to comply with the Missouri and Kansas requirements through the end of November 2012. Additional RECs were retired in January of 2013 to complete the process for 2012. In the future, we will continue to retain a sufficient amount of RECs to meet any current or future requirements.

Gas Segment

The acquisition of Missouri Gas in June 2006 involved the property transfer of two former manufactured gas plant (FMGP) sites owned by predecessors. Site #1 in Chillicothe, Missouri is listed in the MDNR Registry of Confirmed Abandoned or Uncontrolled Hazardous Waste Disposal Sites in Missouri. No remediation of this site is expected to be required in the near term. We have received a letter stating no further action is required from the MDNR with respect to Site #2 in Marshall, Missouri. We have incurred \$0.2 million in remediation costs and estimate further remediation costs at these two FMGP sites to be minimal.

Note 8 - Retirement Benefits

Net periodic benefit cost, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset, is comprised of the following components and is shown for our noncontributory defined benefit pension plan, our supplemental retirement program (SERP) and other postretirement benefits (OPEB) (in thousands):

Three	months	ended	June 30
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	Pension Benefits		SERP		OPEB	
	2013	2012	2013	2012	2013	2012
Service cost	\$ 1,859	\$ 1,628	\$ 52	\$ 7	\$ 715	\$ 565
Interest cost	2,523	2,551	94	56	922	1,032
Expected return on plan assets	(3,089)	(3,076)	-	-	(1,077)	(1,041)
Amortization of prior service cost (1)	133	133	(2)	(2)	(253)	(253)
Amortization of net actuarial loss (1)	2,632	1,950	180	76	481	468
Net periodic benefit cost	\$ 4,058	\$ 3,186	\$ 324	\$ 137	\$ 788	\$ 771

Six months ended June 30.

	Pension Benefits		SI	SERP		ЕВ
	2013	2012	2013	2012	2013	2012
Service cost	\$ 3,727	\$ 3,256	\$ 67	\$ 15	\$ 1,470	\$ 1,129
Interest cost	5,031	5,102	157	111	1,913	2,065
Expected return on plan assets	(6,214)	(6,151)	-	-	(2,176)	(2,083)
Amortization of prior service cost (1)	266	266	(4)	(4)	(505)	(505)
Amortization of net actuarial loss (1)	5,223	3,899	284	153	1,131	935
Net periodic benefit cost	\$ 8,033	\$ 6,372	\$ 504	\$ 275	\$ 1,833	\$ 1,541

Twelve months ended June 30.

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	Pension Benefits		SERP		OPEB	
	2013	2012	2013	2012	2013	2012
Service cost	\$ 6,732	\$ 6,054	\$ 104	\$ 62	\$ 2,742	\$ 2,262
Interest cost	10,187	10,305	308	203	3,885	4,257
Expected return on plan assets	(12,372)	(11,721)	-	-	(4,229)	(4,161)
Amortization of prior service cost (1)	531	532	(8)	(8)	(1,011)	(1,011)
Amortization of net actuarial loss (1)	9,259	6,647	520	238	1,858	1,816
Net periodic benefit cost	\$ 14,337	\$ 11,817	\$ 924	\$ 495	\$ 3,245	\$ 3,163

(1) Amounts are amortized from our regulatory asset originally recorded upon recognizing our net pension liability on the balance sheet.

In accordance with our regulatory agreements, our pension funding policy is to make contributions that are at least equal to the greater of either the minimum funding requirements of ERISA or the accrued cost of the plan. We made pension contributions of approximately \$16.2 million in July 2013, which are expected to satisfy our funding requirements for the year. The actual minimum funding requirements will be determined based on the results of the actuarial valuations. Our OPEB funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits.

Note 9- Stock-Based Awards and Programs

Our performance-based restricted stock awards, stock options and their related dividend equivalents and time-vested restricted stock awards are valued as liability awards, in accordance with fair value guidelines. We allow employees to elect to have taxes in excess of the minimum statutory requirements withheld from their awards and, therefore, the awards are classified as liability instruments under the ASC guidance on share based payment. Awards treated as liability instruments must be revalued each period until settled, and cost is accrued over the requisite service period and adjusted to fair value at each reporting period until settlement or expiration of the award.

We recognized the following amounts in compensation expense and tax benefits for all of our stock-based awards and programs for the applicable periods ended June 30 (in thousands):

	Three Months Ended		Six Month	ns Ended	Twelve Months Ended	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
Compensation Expense	\$ 420	\$ 376	\$ 1,711	\$ 1,198	\$ 2,376	\$ 2,004
Tax Benefit Recognized	146	128	622	427	844	702

Activity for our various stock plans for the six months ended June 30, 2013 is summarized below:

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards are granted to qualified individuals consisting of the right to receive a number of shares of common stock at the end of the restricted period assuming performance criteria are met. The fair value of the outstanding restricted stock awards was estimated using a Monte Carlo option valuation model. The assumptions used in the model for each grant year are noted in the following table:

	Fair Value of Grants Outstanding at June 3			
	2013	2012		
Risk-free interest rate	0.10% to 0.50%	0.17% to 0.35%		
Expected volatility of Empire stock	20.4%	20.9%		
Expected volatility of peer group stock	17.6% to 17.9%	12.7% to 44.2%		
Expected dividend yield on Empire stock	4.5%	4.7%		
Expected forfeiture rates	3%	3%		
Plan cycle	3 years	3 years		
Fair value percentage	8.0% to 104.0%	34.0% to 101.0%		
Weighted average fair value per share	\$17.84	\$12.64		

Non-vested performance-based restricted stock awards (based on target number) as of June 30, 2013 and 2012 and changes during the six months ended June 30, 2013 and 2012 were as follows:

	2013 Number	Weighted Average	2012 Number	Weighted Average
Outstanding at January 1,	<u>of shares</u> 33,900	Grant Date Price \$20.25	of shares 37,400	Grant Date Price \$19.28
	26,300	•	10,000	•
Granted	•	\$21.36	,	\$20.97
Awarded	(4,460)	\$18.36	(7,823)	\$18.12
Not Awarded	<u>(8,540)</u>	\$18.36	(5,677)	\$18.12
Nonvested at June 30,	47,200	\$21.39	33,900	\$20.25

At June 30, 2013, there was \$0.6 million of total unrecognized compensation cost related to estimated outstanding awards. This cost will be recognized over the outstanding years remaining in the vesting period.

Time-Vested Restricted Stock Awards

Beginning in 2011, we began granting, to qualified individuals, time-vested restricted stock awards that vest after a three-year period, in lieu of stock options. No dividend rights accumulate during the vesting period. Time-vested restricted stock is valued at an amount equal to the fair market value of our common stock on the date of grant. If employment terminates during the vesting period because of death, retirement, or disability, the participant is entitled to a pro-rata portion of the time-vested restricted stock awards such participant would otherwise have earned, which is distributed six months following the date of termination, with the remainder of the award forfeited. If employment is terminated during the vesting period for reasons other than those listed above, the time-vested restricted stock awards will be forfeited on the date of the termination, unless the Board of Directors Compensation Committee determines, in its sole discretion, that the participant is entitled to a pro-rata portion of the award.

The fair value measurements for each grant year are noted in the following table:

	Fair Value of Grants Outsta	anding at June 30
	<u>2013</u>	<u>2012</u>
Total unrecognized compensation cost (in millions)	\$ 0.2	less than \$0.1
Recognition period	0.4 years to 2.6 years	1.6 years
Fair value	\$ 19.55	\$ 18.38

No shares of time-vested restricted stock were granted in 2012 as a result of the limitation on incentive compensation in place in 2011. A summary of time vested restricted stock activity under the plan for 2012 and 2013 is presented in the table below:

	June 3	<u>0, 2013</u>	<u>June 30, 2012</u>			
		<u>Weighted</u> Average Fair		Weighted Average Fair		
	Number of shares	Market Value	Number of shares	Market Value		
Outstanding at January 1,	3,300	\$ 20.38	3,433	\$ 21.84		
Granted	21,600	21.36	-	-		
Vested	-	_	-	-		
Distributed	-	-	(133)	\$ 20.13		
Forfeited	-	-	-	-		
Vested but not distributed	-	-	-	-		
Outstanding at end of period	24,900	\$ 22.31	3,300	\$ 20.35		

All time-vested restricted stock awards are classified as liability instruments, which must be revalued each period until settled. The cost of the awards is generally recognized over the requisite (explicit) service period.

Stock Options

Stock option grants vest upon satisfaction of service conditions. The cost of the awards is generally recognized over the requisite (explicit) service period. The fair value of the outstanding options was estimated as of June 30, 2013 and 2012, under a Black-Scholes methodology. The assumptions used in the valuations are shown below:

	Fair Value of Grants Outstanding at June 3					
	<u>2013</u>	<u>2012</u>				
Risk-free interest rate	0.09% to 0.43%	0.20% to 0.54%				
Expected dividend yield	4.50%	4.70%				
Expected volatility	24.0%	25.0%				
Expected life in months	78	78				
Market value	\$ 22.31	\$ 21.10				
Weighted average fair value per option	\$ 1.55	\$ 1.80				

A summary of option activity under the plan during the quarters ended June 30, 2013 and June 30, 2012 is presented below:

·		<u>2013</u> Weighted Average		<u>2012</u> Weighted Average
	Options	Exercise Price	Options	Exercise Price
Outstanding at January 1,	163,300	\$22.13	190,300	\$21.56
Granted	-	-	-	-
Exercised	40,200	\$21.66	27,000	\$18.12
Outstanding at June 30,	<u>123,100</u>	\$23.19	<u>163,300</u>	\$22.13
Exercisable at June 30,	<u>123,100</u>	\$23.19	<u>128,500</u>	\$23.15

The intrinsic value of the unexercised options is the difference between Empire's closing stock price on the last day of the quarter and the exercise price multiplied by the number of in the money options had all option holders exercised their option on the last day of the quarter. The intrinsic value is zero if such closing price is less than the exercise price. The table below shows the aggregate intrinsic values at June 30, 2013 and 2012:

	<u>2013</u>	<u>2012</u>
Aggregate intrinsic value (in millions)	Less than \$0.1	\$0.1
Weighted-average remaining contractual life of outstanding options	2.6 years	3.7 years
Range of exercise prices	\$21.79 to \$23.81	\$18.36 to \$23.81
Total unrecognized compensation expense (in millions) related to non-vested options and related dividend equivalents granted		
under the plan	0.0	less than \$0.1
Recognition period		0.6 years

Employee Stock Purchase Plan

Our Employee Stock Purchase Plan (ESPP) permits the grant to eligible employees of options to purchase common stock at 90% of the lower of market value at date of grant or at date of exercise. The lookback feature of this plan is valued at 90% of the Black-Scholes methodology plus 10% of the maximum subscription price. As of June 30, 2013, there were 127,774 shares available for issuance in this plan.

	2013	2012
Subscriptions outstanding at June 30	62,793	72,899
Maximum subscription price(1)	\$19.58	\$17.95
Shares of stock issued	68,099	65,919
Stock issuance price	\$17.95	\$17.27

⁽¹⁾ Stock will be issued on the closing date of the purchase period, which runs from June 1, 2013 to May 31, 2014.

Assumptions for valuation of these shares are shown in the table below.

	2013	2012
Weighted average fair value of grants at June 30	\$ 2.78	\$ 3.19
Risk-free interest rate	0.14%	0.17%
Expected dividend yield	4.60%	5.00%
Expected volatility	14.00%	24.00%
Expected life in months	12	12
Grant Date	6/1/13	6/1/12

Note 10- Regulated Operating Expenses

The following table sets forth the major components comprising "regulated operating expenses" under "Operating Revenue Deductions" on our consolidated statements of income (in thousands) for all periods presented ended June 30:

	Three	Three	Six	Six	Twelve	Twelve
	Months	Months	Months	Months	Months	Months
	Ended	Ended	Ended	Ended	Ended	Ended
	2013	2012	2013	2012	2013	2012
Electric transmission and distribution expense	\$ 5,950	\$ 4,264	\$ 10,979	\$ 8,372	\$ 19,690	\$ 16,493
Natural gas transmission and distribution expense	577	664	1,122	1,316	2,250	2,561
Power operation expense (other than fuel)	4,515	3,604	8,307	7,399	16,545	15,529
Customer accounts and assistance expense	2,619	2,584	5,198	5,018	10,391	10,297
Employee pension expense (1)	2,757	2,539	5,399	5,074	10,505	10,060
Employee healthcare plan (1)	2,408	2,324	5,195	4,562	10,458	8,664
General office supplies and expense	3,163	2,523	6,592	5,275	12,093	10,298
Administrative and general expense	3,603	3,573	7,918	7,792	15,217	15,384
Allowance for uncollectible accounts	1,044	753	1,790	1,345	3,483	3,446
Regulatory reversal of gain on sale of assets	-	-	1,236	-	1,236	_
Miscellaneous expense	11	16	48	39	95	102
Total	\$ 26,647	\$ 22,844	\$ 53,784	\$ 46,192	\$101,963	\$ 92,834

⁽¹⁾ Does not include capitalized portion of costs, but reflects the GAAP expensed cost plus or minus costs deferred to and amortized from a regulatory asset and/or a regulatory liability for Missouri, Kansas and Oklahoma jurisdictions.

Note 11– Segment Information

We operate our business as three segments: electric, gas and other. As part of our electric segment, we also provide water service to three towns in Missouri. The other segment consists of our fiber optics business.

The tables below present statement of income information, balance sheet information and capital expenditures of our business segments.

	For the quarter ended June 30, 2013									
		Electric		Gas	Other		Eliminations			<u>Total</u>
(\$-000's)										
Statement of Income Information										
Revenues	\$	127,026	\$	7,777	\$	1,991	\$	(148)	\$	136,646
Depreciation and amortization		16,205		927		503		-		17,635
Federal and state income taxes		6,948		(129)		230		-		7,049
Operating income		19,994		744		372		-		21,110
Interest income		3		34		2		(29)		10
Interest expense		9,557		976		-		(29)		10,504
Income from AFUDC (debt and equity)		1,331		8		-		-		1,339
Net income		11,498		(214)		374		-		11,658
Capital Expenditures	\$	36,535	\$	1,463	\$	502			\$	38,500

	For the quarter ended June 30, 2012								
	Electric	-	Gas		Other		minations		Total
(\$-000's)									
Statement of Income Information									
Revenues	\$ 124,091	\$	5,804	\$	1,885	\$	(148)	\$	131,632
Depreciation and amortization	13,759		861		448		-		15,068
Federal and state income taxes	6,745		(238)		253		-		6,760
Operating income	19,834		534		394		-		20,762
Interest income	118		95		1		(91)		123
Interest expense	9,174		976		_		(91)		10,059
Income from AFUDC (debt and equity)	170		1		_		-		171
Net income	10,691		(394)		411		-		10,708
Capital Expenditures	\$ 33,745	\$	844	\$	594			\$	35,183
		Fc	or the six m	nont	hs ended	June	30, 2013		
	Electric	-	Gas		Other		minations		Total
(\$-000's)						·			
Statement of Income Information									
Revenues	\$ 255,788	\$	28,270	\$	4,024	\$	(296)	\$	287,786
Depreciation and amortization	30,887		1,851		998		-		33,736
Federal and state income taxes	12,943		1,076		512		-		14,531
Operating income Interest income	38,509 497		3,639 105		820 7		(92)		42,968 517
Interest expense	18,893		1,953		,		(92)		20,754
•	2,161		1,955		_		(32)		2,170
Income from AFUDC (debt and equity) Net income	2,101		1,735		- 831		- -		24,287
Capital Expenditures	\$ 73,070	\$	2,196	\$	942			\$	76,208
	,		ŕ						ŕ
		Fo	or the six m						
(† 0001-)	<u>Electric</u>		<u>Gas</u>		<u>Other</u>	Elii	<u>minations</u>		<u>Total</u>
(\$-000's) Statement of Income Information									
	\$ 243,817	\$	21,487	\$	2 760	\$	(296)	æ	268,776
Revenues Depreciation and amortization	27,329	Ф	1,780	Φ	3,768 894	Φ	(290)	Φ	30,003
Federal and state income taxes	11,932		459		568		_		12,959
Operating income	38,078		2,588		907		- -		41,573
Interest income	288		166		1		(153)		302
Interest expense	19,202		1,953		-		(153)		21,002
Income from AFUDC (debt and equity)	268		2		_		(.55)		270
Net income	18,864		725		923		-		20,512

1,569

\$ 1,538

\$ 69,970

\$ 66,863

Capital Expenditures

	For the twelve months ended June 30, 2013								
	Electric		<u>Gas</u>		<u>Other</u>	Eliminations			<u>Total</u>
(\$-000's)									
Statement of Income Information									
Revenues	\$ 522,624	\$	46,632	\$	7,443	\$	(592)	\$	576,107
Depreciation and amortization	58,869		3,669		1,642		-		64,180
Federal and state income taxes	33,277		1,406		1,047		-		35,730
Operating income	89,876		6,055		1,684		-		97,615
Interest income	1,155		262		13		(243)		1,187
Interest expense	37,558		3,905		-		(243)		41,220
Income from AFUDC (debt and equity)	3,811		18		-		-		3,829
Net income	55,487		2,267		1,702		-		59,456
Capital Expenditures	\$ 149,619	\$	4,198	\$	2,003			\$	155,820

	For the twelve months ended June 30, 2012								
	<u>Electric</u>	Gas	<u>Other</u>	Eliminations	<u>Total</u>				
(\$-000's)									
Statement of Income Information									
Revenues	\$ 519,403	\$ 39,625	\$ 7,389	\$ (592)	\$ 565,825				
Depreciation and amortization	53,956	3,530	1,832	-	59,318				
Federal and state income taxes	32,602	766	1,065	-	34,433				
Operating income	90,596	4,980	1,949	-	97,525				
Interest income	805	296	1	(283)	819				
Interest expense	39,243	3,909	4	(283)	42,873				
Income from AFUDC (debt and equity)	626	4	-	-	630				
Net Income	51,441	1,215	1,731	-	54,387				
Capital Expenditures	\$ 110,478	\$ 4,657	\$ 3,646		\$ 118,781				

As of June 30, 2013

(\$-000's)	<u>Electric</u>	Gas ⁽¹⁾	<u>Other</u>	Elimination	<u>Total</u>
Balance Sheet Information					
Total assets	\$ 2,082,513	\$ 150,733	\$ 29,494	\$ (94,103)	\$ 2,168,637

⁽¹⁾ Includes goodwill of \$39,492.

As of December 31, 2012

(\$-000's)	<u>Electric</u>	Gas ⁽¹⁾	<u>Other</u>	Elimination	<u>Total</u>
Balance Sheet Information					
Total assets	\$ 2,034,399	\$ 148,814	\$ 28,871	\$ (85,715)	\$ 2,126,369

⁽¹⁾ Includes goodwill of \$39,492.

Note 12– Income Taxes

The following table shows the changes in our provision for income taxes (in millions) and our consolidated effective federal and state income tax rates for the applicable periods ended June 30,:

	Three Months Ended		Six-Months Ended		Twelve Months Ende	
	<u>2013</u>	2012	<u>2013</u>	2012	2013	<u>2012</u>
Consolidated provision for income taxes Consolidated effective federal and state	\$ 7.0	\$ 6.8	\$ 14.5	\$ 13.0	\$ 35.7	\$ 34.4
income tax rates	37.7%	38.7%	37.4%	38.7%	37.5%	38.8%

The effective income tax rate for the three, six and twelve month periods ended June 30, 2013 is lower than comparable periods in 2012 primarily due to higher equity AFUDC income in 2013 compared with 2012.

We do not have any unrecognized tax benefits as of June 30, 2013. We did not recognize any significant interest or penalties in any of the periods presented. We do not expect any significant changes to our unrecognized tax benefits over the next twelve months.

Item 2. <u>Management's Discussion and Analysis of Financial Condition and Results of</u> Operations

EXECUTIVE SUMMARY

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE) is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas, including the sale of wholesale energy to four towns in Missouri and Kansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary which provides natural gas distribution to customers in 48 communities in northwest, north central and west central Missouri. Our other segment consists of our fiber optics business.

During the twelve months ended June 30, 2013, our gross operating revenues were derived as follows:

Electric segment sales*	90.7%
Gas segment sales	8.1
Other segment sales	1.2

^{*}Sales from our electric segment include 0.3% from the sale of water.

Earnings

The following table represents our basic and diluted earnings per weighted average share of common stock for the applicable periods ended June 30 (in dollars):

	Three Months Ended		Six Months Ended		Twelve Months Ended	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
Basic and diluted earnings per weighted						
average share of common stock	\$ 0.27	\$ 0.25	\$ 0.57	\$ 0.49	\$ 1.40	\$ 1.29

Increased electric and gas gross margins positively impacted net income for all three periods presented as of June 30, 2013. We define electric gross margins as electric revenues less fuel and purchased power costs. We define gas gross margins as gas operating revenues less cost of gas in rates

Increased electric customer rates resulting from our recently settled Missouri rate case (see "Recent Activities - Regulatory Matters" below) drove increases in revenue and electric gross margin during the quarter ended June 30, 2013. Average customer counts increased quarter over quarter,

but were tempered slightly by an increase in seasonal disconnect activity compared to the 2012 quarter.

The increases in revenue and electric gross margin were partially offset by weather that was slightly more temperate than normal. June 2013 was considerably cooler than the very hot June 2012, resulting in a delay in the transition from heating to cooling season. Increases in regulated operating expense and depreciation and amortization expense also negatively impacted quarter over quarter results.

Increased revenues, due to the April 1, 2013 Missouri rate increase, and weather were positive drivers for the six months ended June 30, 2013. The first quarter of 2013 was considerably colder than the first quarter of 2012, when the warmest temperatures on record were recorded. Decreased maintenance and repairs expense and increased AFUDC also positively impacted net income for the six months ended June 30, 2013

Negative drivers for the six months ended June 30, 2013 as compared to the same period last year included increased regulated operating expense, increased depreciation and amortization expense and the regulatory write off of approximately \$3.6 million (see "Recent Activities - Regulatory Matters" below).

Revenue and electric gross margin during the twelve months ended June 30, 2013 were positively impacted by the increased Missouri customer electric rates discussed above, improving customer counts and a change in our unbilled revenue estimate in the third quarter of 2012. A return to more normal summer and winter weather during the 2013 period negatively impacted gross margin compared to the 2012 period.

Increased regulated operating expense, increased depreciation and amortization expense and the previously mentioned regulatory write off also negatively impacted year over year results.

Factors impacting gross margin and net income for the quarter, six months and twelve months ended June 30, 2013, are presented on a segment basis under "Results of Operations" below.

The table below sets forth a reconciliation of basic and diluted earnings per share between the three months, six months and twelve months ended June 30, 2012 and June 30, 2013, which is a non-GAAP presentation. The economic substance behind our non-GAAP earnings per share (EPS) measure is to present the after tax impact of significant items and components of the statement of income on a per share basis before the impact of additional stock issuances.

We believe this presentation is useful to investors because the statement of income does not readily show the EPS impact of the various components. This could limit the readers' understanding of the reasons for the EPS change from the previous year's EPS. This information is useful to management, and we believe this information is useful to investors, to better understand the reasons for the fluctuation in EPS between the prior and current years on a per share basis.

This reconciliation may not be comparable to other companies or more useful than the GAAP presentation included in the statement of income. We also note that this presentation does not purport to be an alternative to earnings per share determined in accordance with GAAP as a measure of operating performance or any other measure of financial performance presented in accordance with GAAP. Management compensates for the limitations of using non-GAAP financial measures by using them to supplement GAAP results to provide a more complete understanding of the factors and trends affecting the business than GAAP results alone. The dilutive effect of additional shares issued included in the table reflects the estimated impact of all shares issued during the periods ended June 30.

	Three Months	Six Months	Twelve Months
	Ended	Ended	Ended
Earnings Per Share – 2012	\$ 0.25	\$ 0.49	\$ 1.29
Revenues Electric segment Gas segment Other segment Total Revenue Electric fuel and purchased power Cost of natural gas sold and transported Margin	\$ 0.04	\$ 0.17	\$ 0.04
	0.03	0.10	0.10
	0.00	0.00	0.00
	0.07	0.27	0.14
	0.05	0.05	0.21
	(0.02)	(0.07)	(0.07)
	0.10	0.25	0.28
Operating – electric segment Operating –gas segment Operating –other segment Maintenance and repairs Depreciation and amortization Loss on plant disallowance Other taxes Interest charges AFUDC Change in effective income tax rates Dilutive effect of additional shares issued Earnings Per Share – 2013	(0.06)	(0.11)	(0.14)
	0.00	0.00	0.01
	0.00	0.00	(0.01)
	0.01	0.01	0.02
	(0.04)	(0.05)	(0.07)
	0.00	(0.03)	(0.03)
	(0.01)	(0.02)	(0.03)
	(0.01)	0.00	0.02
	0.02	0.03	0.05
	0.01	0.01	0.03
	0.00	(0.01)	(0.02)
	\$ 0.27	\$ 0.57	\$ 1.40

Recent Activities

Regulatory Matters

On February 22, 2013, we filed a Nonunanimous Stipulation and Agreement (Agreement) with the Missouri Public Service Commission (MPSC) which issued an order approving the Agreement on February 27, 2013, effective March 6, 2013. The Agreement provided for an annual increase in base revenues for our Missouri electric customers in the amount of approximately \$27.5 million, effective April 1, 2013, and the continuation of the current fuel adjustment mechanism. The Agreement also included an increase in depreciation rates, recovery of deferred tornado costs over the next ten years and the continuation of tracking mechanisms for expenses related to employee pension, retiree health care, vegetation management, and latan 2, latan Common and Plum Point operating and maintenance costs. In addition, the Agreement included a write-off of approximately \$3.6 million, consisting of a \$2.4 million disallowance for the prudency of certain construction expenditures for latan 2 and a \$1.2 million regulatory reversal of a prior period gain on sale of our Asbury unit train, which is included in regulated operating expenses. We also agreed not to implement a Missouri general rate increase prior to October 1, 2014. As initially filed on July 6, 2012, we had requested an annual increase in base rates for our Missouri electric customers in the amount of \$30.7 million, or 7.56%, the continuation of the fuel adjustment clause, new depreciation rates and the recovery of various expenses.

On May 18, 2012, we filed a request with the Federal Energy Regulatory Commission (FERC) to implement a cost-based transmission formula rate (TFR) to be effective August 1, 2012. On July 31, 2012, the FERC suspended the TFR for five months and set the filing for hearing and settlement procedures. On June 13, 2013, we, the Kansas Corporation Commission and the cities of Monett, Mt. Vernon and Lockwood, Missouri and Chetopa, Kansas, filed a unanimous Settlement Agreement (Agreement) with the FERC. The Agreement includes a TFR that establishes an ROE of 10.0%. The Agreement calls for the TFR to be updated annually with the new updated TFR rates effective on July 1 of each year. FERC action on the Agreement is pending.

For additional information, see "Rate Matters" below.

Integrated Resource Plan

We filed our Integrated Resource Plan (IRP) with the MPSC on July 1, 2013. The IRP analysis of future loads and resources is normally conducted once every three years. Our IRP supports our Compliance Plan discussed in Note 7 of "Notes to Consolidated Financial Statements (Unaudited)".

Financings

As described in Note 6, on October 30, 2012, we entered into a Bond Purchase Agreement for a private placement of \$30.0 million of 3.73% First Mortgage Bonds due May 30, 2033 and \$120.0 million of 4.32% First Mortgage Bonds due May 30, 2043. The delayed settlement of both series of bonds occurred on May 30, 2013. Interest is payable semi-annually on the bonds on each May 30 and November 30, commencing November 30, 2013.

A portion of the proceeds from the above sale of bonds was used to redeem all \$98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013. The remaining proceeds will be used for general corporate purposes.

Union Contract

In May 2013, Local 1464 of the International Brotherhood of Electrical Workers (IBEW) ratified a four-year agreement with EDG, effective June 1, 2013. At December 31, 2012, 34 EDG employees were members of Local 1464 of the IBEW.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the three month, six month and twelve month periods ended June 30, 2013, compared to the same periods ended June 30, 2012.

The following table represents our results of operations by operating segment for the applicable periods ended June 30 (in millions):

	Three Mont	Three Months Ended		Six Months Ended		Twelve Months Ended	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>	
Electric	\$ 11.5	\$ 10.7	\$ 21.7	\$ 18.9	\$ 55.5	\$ 51.5	
Gas	(0.2)	(0.4)	1.8	0.7	2.3	1.2	
Other	0.4	0.4	0.8	0.9	1.7	<u> </u>	
Net income	<u>\$ 11.7</u>	\$ 10.7	\$ 24.3	\$ 20.5	\$ 59.5	\$ 54.4	

Electric Segment

Gross Margin

As shown in the table below, electric segment gross margin increased approximately \$6.4 million during the second quarter of 2013 as compared to the second quarter of 2012, mainly due to increased revenues as a result of the Missouri rate increase that became effective April 1, 2013.

The electric gross margin increased approximately \$15.5 million for the six months ended June 30, 2013 as compared to the same period in 2012, mainly due to increased demand resulting from favorable weather in the first quarter of 2013 and increased revenues due to the Missouri rate increase.

These factors likewise impacted the twelve months ended June 30, 2013 period. Electric gross margin increased approximately \$17.4 million as compared to the same period in 2012. A change in our unbilled revenue estimate in the third quarter of 2012 and improved customer counts also favorably impacted the twelve month period over period results.

The table below represents our electric gross margins for the applicable periods ended June 30 (dollars in millions):

	Three Months Ended				Six Months Ended				Twelve Mon		nths Ended	
	<u>2013</u>		<u>3 2012</u>		<u>2013</u>		<u>2012</u>		<u>2013</u>		2	2012
Electric segment revenues	\$	127.0	\$	124.1	\$	255.8	\$	243.8	\$	522.6	\$	519.4
Fuel and purchased power	_	42.0	_	45.5		87.3	_	90.8		175.4	_	189.6
Electric segment gross margins	\$	85.0	\$	78.6	\$	168.5	\$	153.0	\$	347.2	\$	329.8
Margin as % of total electric segment revenues		66.9%		63.3%		65.9%		62.8%		66.4%		63.5%

Although a non-GAAP presentation, we believe the presentation of gross margin is useful to investors and others in understanding and analyzing changes in our electric operating performance from one period to the next, and have included the analysis as a complement to the financial information we provide in accordance with GAAP. However, these margins may not be comparable to other companies' presentations or more useful than the GAAP information we provide elsewhere in this report.

Sales and Revenues

Electric operating revenues comprised approximately 93.0% of our total operating revenues during the second quarter of 2013.

The amounts and percentage changes from the prior periods in kilowatt-hour ("kWh") sales by major customer class for on-system sales and off-system sales for the applicable periods ended June 30, were as follows:

kWh Sales

				\····	,				
	Second	Second		6 Months	6 Months		12 Months	12 Months	
	Quarter	Quarter	%	Ended	Ended	%	Ended	Ended	%
Customer Class	2013	2012	Change ⁽¹⁾	2013	2012	Change ⁽¹⁾	2013	2012	Change ⁽¹⁾
Residential	387.3	389.1	(0.5)%	958.3	865.6	10.7%	1,943.5	1,857.5	4.6%
Commercial	377.0	399.5	(5.6)	736.7	737.3	3 (0.1)	1,557.7	1,553.4	0.3
Industrial	264.4	269.6	(1.9)	505.0	511.3	3 (1.2)	1,022.1	1,034.4	(1.2)
Wholesale on-system	83.9	89.0	(5.8)	168.4	173.5	(3.0)	348.0	362.0	(3.9)
Other ⁽²⁾	<u>31.5</u>	<u>29.1</u>	8.5	<u>64.5</u>	<u>60.3</u>	<u>7</u> .0	<u>128.4</u>	<u>125.0</u>	2.8
Total on-system sales	1,144.1	1,176.3	3 (2.7)	2,432.9	2,348.0	3.6	4,999.7	4,932.3	1.4
Off-system	<u>183.0</u>	<u>171.4</u>	6.8	<u>335.3</u>	<u>308.1</u>	<u>l</u> 8.8	<u>731.2</u>	<u>595.1</u>	22.9
Total KWh Sales	1.327.1	1.347.7	(1.5)	2.768.2			5.730.9	5.527.4	3.7

⁽¹⁾ Percentage changes are based on actual kWh sales and may not agree to the rounded amounts shown above.

KWh sales for our on-system customers decreased 2.7% during the quarter ended June 30, 2013, as compared to the same period in 2012, mainly due to slightly more temperate than normal temperatures during the second quarter of 2013. Total cooling degree days (the cumulative number of degrees that the daily average temperature for each day during that period was above 65°F) for the second guarter of 2013 were 27.7% less than the same period last year and 9.9% more than the 30-year average. Although the second quarter weather is usually measured in total cooling degree days, the slightly more temperate than normal temperatures in the second quarter of 2013 led to total heating degree days (the sum of the number of degrees that the daily average temperature for each day during that period was below 65°F) outnumbering the cooling degree days, and correspondingly, a delay in the transition from heating to cooling season. Total heating degree days for the second quarter of 2013 were 110.7% more than the same period last year and 22.0% more than the 30-year average. KWh sales for our residential and commercial customers decreased during the second quarter of 2013 as compared to the second quarter of 2012 primarily due to the slightly more temperate than normal temperatures and the corresponding delay in the transition from heating to cooling season. The weather related decrease in residential sales was offset by an increase in the average residential customer count.

KWh sales for our on-system customers increased 3.6% during the six months ended June 30, 2013, as compared to the same period in 2012, primarily due to increased demand resulting from colder weather in the first quarter of 2013 as compared to the first quarter of 2012.

⁽²⁾Other kWh sales include street lighting, other public authorities and interdepartmental usage.

KWh sales for our on-system customers increased 1.4% during the twelve months ended June 30, 2013, as compared to the same period in 2012, mainly due to improved customer counts. Residential and commercial kWh sales increased primarily due to the improved customer count.

Industrial sales decreased 1.9%, 1.2% and 1.2% during the quarter, six month and twelve month periods ended June 30, 2013, respectively, due to reductions by several large industrial customers.

We are not modifying our near and longer-term growth estimates disclosed in our 2012 10-K, although, on a weather-normalized basis, kWh sales were relatively flat in the first six months of 2013

The amounts and percentage changes from the prior periods in electric segment operating revenues by major customer class for on-system and off-system sales for the applicable periods ended June 30, were as follows:

Electric Segment Operating Revenues

				(\$ in mil	lions)				
	3 Months	3 Months		6 Months	6 Months		12 Months	12 Months	
	Ended	Ended	%	Ended	Ended	%	Ended	Ended	%
Customer Class	2013	2012	Change ⁽¹⁾	2013	2012	Change ⁽¹⁾	2013	2012	Change ⁽¹⁾
Residential	\$ 47.9	\$ 47.3	1.4%	\$ 109.2	\$ 101.5	7.6%	\$ 222.2	\$ 217.7	2.1%
Commercial	41.0	41.4	(0.9)	75.8	75.8	0.0	158.8	160.9	(1.3)
Industrial	21.1	20.8	1.5	38.2	38.8	(1.5)	78.2	81.2	(3.8)
Wholesale on-system	4.9	4.7	4.1	9.6	8.6	11.5	19.6	19.0	2.9
Other ⁽²⁾	3.7	3.4	9.0	7.3	6.9	5.6	<u> 14.3</u>	<u> 14.1</u>	1.6
Total on-system revenues	\$ 118.6	\$ 117.6	0.9	\$ 240.1	\$ 231.6	3.7	\$ 493.1	\$ 492.9	0.1
Off-system of the original of	4.3	3.6	19.0	8.0	6.8	16.7	<u>16.8</u>	<u>16.1</u>	4.3
Total revenues from kWh									
sales	122.9	121.2	1.5	248.1	238.4	4.0	509.9	509.0	0.2
Miscellaneous revenues ⁽³⁾	3.6	2.5	43.1	6.7	4.6	48.2	10.7	8.6	24.0
Total electric operating									
revenues	\$ 126.5	\$ 123.7	2.3	\$ 254.8	\$ 243.0	4.9	\$ 520.6	\$ 517.6	0.6
Water revenues	0.5	0.4	18.1	1.0	0.8	21.3	2.0	1.8	11.6
Total electric segment									
operating revenues	\$ 127.0	\$ 124.1	2.4	\$ 255.8	\$ 243.8	4.9	\$ 522.6	\$ 519.4	0.6

(1) Percentage changes are based on actual revenues and may not agree to the rounded amounts shown above.

Revenues for our on-system customers increased \$1.1 million during the second quarter of 2013 as compared to the second quarter of 2012. Rate changes from the April 2013 Missouri rate increase, increased revenues an estimated \$7.8 million. Improved customer counts increased revenues an estimated \$1.1 million. These revenue increases were partially offset by a \$3.2 million decrease in fuel recovery revenue (and corresponding reduction in fuel expenses, resulting in no net effect on gross margin) from Missouri customers during the second quarter of 2013 compared to the prior year quarter. The impact of weather and other related factors decreased revenues an estimated \$4.6 million. The cumulative effect of these revenue changes had a favorable impact on gross margin quarter over quarter.

Revenues for our on-system customers increased \$8.5 million for the six months ended June 30, 2013 as compared to the same period in 2012. Rate changes from the April 2013 Missouri rate increase, contributed an estimated \$8.8 million to revenues. Weather and other related factors increased revenues an estimated \$5.0 million during the six months ended June 30, 2013. Improved customer counts increased revenues an estimated \$2.5 million. These revenue increases were partially offset by a \$7.8 million decrease in fuel recovery revenue (and corresponding reduction in fuel expenses, resulting in no net effect on gross margin) from Missouri customers during the six months ended June 30, 2013 compared to the same period in 2012. The cumulative effect of the revenue changes mentioned above had a favorable impact on gross margin for the six months ended 2013 period.

Revenues for our on-system customers increased \$0.2 million for the twelve months ended June 30, 2013 as compared to the same period in 2012. Rate changes, primarily the April 2013

⁽²⁾ Other operating revenues include street lighting, other public authorities and interdepartmental usage.

⁽³⁾ Miscellaneous revenues include transmission service revenue, late payment fees, renewable energy credit sales, rent, etc.

Missouri rate increase and the January 2012 Kansas rate increase, contributed an estimated \$8.2 million to revenues. Improved customer counts increased revenues an estimated \$7.4 million. Additionally, a change in our unbilled revenue estimate in the third quarter of 2012 added \$3.4 million to revenues. These revenue increases were offset by a \$13.7 million decrease in fuel recovery revenue (and corresponding reduction in fuel expenses, resulting in no net effect on gross margin) from Missouri customers during the twelve months ended June 30, 2013 compared to the same period in 2012. Weather and other related factors decreased revenues an estimated \$5.1 million. The cumulative year over year revenue changes mentioned above impacted gross margin positively.

Off-System Electric Transactions.

In addition to sales to our own customers, we also sell power to other utilities as available, including through the Southwest Power Pool (SPP) Energy Imbalance Services (EIS) market. See "— Competition and Markets" below. The majority of our off-system sales margins are included as a component of the fuel adjustment clause in our Missouri, Kansas and Oklahoma jurisdictions and our transmission rider in our Arkansas jurisdiction and generally adjust the fuel and purchased power expense. As a result, nearly all of the off-system sales margin flows back to the customer and has little effect on margin or net income.

Miscellaneous Revenues

Our miscellaneous revenues increased approximately \$1.1 million, \$2.1 million and \$2.1 million during the quarter, six month and twelve month periods ended June 30, 2013, respectively, primarily due to increased transmission revenues. These miscellaneous revenues are comprised mainly of transmission revenues, late payment fees and renewable energy credit sales.

Operating Revenue Deductions – Fuel and Purchased Power

The table below is a reconciliation of our actual fuel and purchased power expenditures (netted with the regulatory adjustments) to the fuel and purchased power expense shown on our statements of income for the applicable periods ended June 30, 2013 and 2012.

				Months ded			lonths ded		Twelve M End			
(in millions)	2	2013		2012		2013	2	012		2013		2012
Actual fuel and purchased power expenditures	\$	43.7	\$	39.9	\$	91.5	\$	80.6	\$	184.5	\$	181.1
Missouri fuel adjustment recovery (1)		(0.4)		2.7		(0.9)		7.0		(4.4)		9.3
Missouri fuel adjustment deferral ⁽²⁾ Kansas and Oklahoma regulatory		(0.7)		3.2		(1.9)		5.0		(1.6)		1.7
adjustments ⁽²⁾		(0.1)		0.5		-		8.0		0.1		0.4
SWPA amortization ⁽³⁾		(0.7)		(0.7)		(1.4)		(1.3)		(2.9)		(2.7)
Unrealized (gain)/loss on derivatives Total fuel and purchased power	,	0.2		(0.1)				(1.3)		(0.3)		(0.2)
expense per income statement	\$	42.0	\$	45.5	\$	87.3	\$	90.8	\$	175.4	\$	189.6

⁽¹⁾A positive amount indicates costs recovered from customers from under recovery in prior deferral periods. A negative amount indicates costs refunded to customers from over recovery in prior deferral periods.

Operating Revenue Deductions – Other Than Fuel and Purchased Power

The table below shows regulated operating expense increases/(decreases) for the applicable periods ended June 30, 2013 as compared to the same periods in 2012.

⁽²⁾A negative amount indicates costs have been under recovered from customers and a positive amount indicates costs have been over recovered from customers.

⁽³⁾ Missouri ten year amortization of the \$26.6 million payment received from the SWPA in September, 2010.

	Three Months Ended	Six Months Ended	Twelve Months Ended
(in millions)	2013 vs. 2012	2013 vs. 2012	2013 vs. 2012
Employee pension expense	\$ 0.2	\$ 0.3	\$ 0.5
Steam power other operating expense	0.8	0.7	0.8
Transmission expense	1.5	2.5	3.2
Distribution expense	0.2	0.1	0.0
Regulatory reversal of gain on prior			
period sale of assets	0.0	1.2	1.2
Employee health care expense	0.1	0.6	1.7
Customer accounts expense ⁽¹⁾	0.3	0.4	0.0
Banking fees	(0.1)	(0.5)	(0.9)
Regulatory commission expense	0.0	0.1	(0.5)
Property insurance	0.1	0.3	0.6
Injuries and damages expense	0.1	0.5	0.4
General labor costs	0.4	1.1	1.4
Professional services	(0.1)	(0.3)	0.3
General office expense	0.2	0.2	0.7
Other miscellaneous accounts (netted)	0.2	<u>0.5</u>	<u> </u>
TOTAL	<u>\$ 3.9</u>	<u>\$ 7.7</u>	<u>\$ 9.5</u>

(1) Primarily uncollectible accounts.

The table below shows maintenance and repairs expense increases/(decreases) for the applicable periods ended June 30, 2013 as compared to the same periods in 2012.

	Three Months Ended	Six Months Ended	Twelve Months Ended
(in millions)	2013 vs. 2012	2013 vs. 2012	2013 vs. 2012
Distribution and transmission maintenance costs	\$ 0.5	\$ (0.6)	\$ (1.9)
Maintenance and repairs expense at the Asbury plant	(0.7)	(0.1)	0.7
Maintenance and repairs expense at the SLCC	(1.2)	(0.5)	(0.5)
Maintenance and repairs expense at the latan plant,			
Energy Center, Plum Point plant and Riverton plant	0.4	0.2	0.0
Other miscellaneous accounts (netted)	0.0	0.1	0.1
TOTAL	\$ (1.0)	\$ (0.9)	\$ (1.6)

Depreciation and amortization expense increased approximately \$2.4 million (17.8%), \$3.6 million (13.0%) and \$4.9 million (9.1%) during the quarter, six month and twelve month periods ended June 30, 2013, respectively, primarily due to increased depreciation rates resulting from our recent Missouri electric rate case settlement and increased plant in service.

Other taxes increased approximately \$0.6 million, \$1.0 million and \$1.7 million during the quarter, six month and twelve month periods ended June 30, 2013, respectively, due to increased property tax reflecting our additions to plant in service and increased municipal franchise taxes.

Gas Segment

Gas Operating Revenues and Sales

The following table details our natural gas sales for the periods ended June 30:

Total Gas Delivered to Customers

	Three Months Ended			Six month	<u>is ended</u>		Twelve mon		
(bcf sales)	<u>2013</u>	<u>2012</u>	% change	<u>2013</u>	<u>2012</u>	% change	<u>2013</u>	<u> 2012</u>	% change
Residential	0.33	0.15	117.5 %	1.67	1.12	49.6 %	2.56	1.99	28.8 %
Commercial	0.18	0.14	34.2	0.79	0.58	35.2	1.26	1.05	19.6
Industrial ⁽¹⁾	0.01	0.01	39.7	0.05	0.04	29.8	0.07	0.07	(2.8)
Other ⁽²⁾	<u>0.01</u>	0.00	390.5	0.02	0.01	58.3	0.03	0.03	31.8
Total retail sales	0.53	0.30	77.7	2.53	1.75	44.5	3.92	3.14	25.1
Transportation sales ⁽¹⁾	0.98	0.92	6.1	2.39	<u>2.14</u>	11.5	<u>4.50</u>	<u>4.11</u>	9.3
Total gas operating sales	1.51	1.22	23.7	4.92	3.89	26.3	8.42	7.25	16.1

⁽¹⁾ The twelve month ended percentage change reflects the transfer of customers from industrial sales to transportation during the first quarter of 2012.

Gas retail sales increased 77.7% during the second quarter of 2013 as compared to the second quarter of 2012 primarily due to cooler than normal temperatures during the second quarter of 2013. Heating degree days were 150.6% more in the second quarter of 2013 as compared to the second quarter of 2012 and 43.4% more than the 30-year average.

Gas retail sales increased 44.5% during the six months ended June 30, 2013 as compared to the same period in 2012 primarily due to colder weather during the first and second quarters of 2013 as compared to the same periods in 2012.

Gas retail sales increased 25.1% during the twelve months ended June 30, 2013 as compared to the same period in 2012 reflecting the colder weather during the first and second quarters of 2013 as compared to the same periods in 2012. Industrial sales decreased slightly, reflecting the transfer of customers from industrial sales to transportation during the first quarter of 2012.

The following table details our natural gas revenues for the periods ended June 30:

Operating Revenues and Cost of Gas Sold

	Three Months Ended			Six mont	hs ended		Twelve months ended			
(\$ in millions)	<u>2013</u>	<u>2012</u>	% change	<u>2013</u>	<u>2012</u>	% change	<u>2013</u>	<u>2012</u>	% change	
Residential	\$ 4.8	\$ 3.3	46.9%	\$ 18.1	\$ 13.3	35.6%	\$ 29.5	\$ 24.5	20.5%	
Commercial	2.1	1.6	26.8	7.7	5.9	31.1	12.6	10.7	17.4	
Industrial ⁽¹⁾	0.0	0.1	(40.4)	0.3	0.3	5.3	0.5	0.5	(7.4)	
Other ⁽²⁾	0.0	0.0	136.4	0.2	0.2	48.0	0.3	0.3	26.9	
Total retail revenues	\$ 6.9	\$ 5.0	39.4	\$ 26.3	\$ 19.7	33.9	\$ 42.9	\$ 36.0	19.2	
Other revenues	0.2	0.1	24.8	0.2	0.2	4.7	0.4	0.4	(6.2)	
Transportation revenues ⁽¹	0.7	0.7	(2.9)	<u>1.7</u>	<u>1.6</u>	6.9	3.3	3.2	3.7	
Total gas operating										
revenues	\$ 7.8	\$ 5.8	34.0	\$ 28.2	\$ 21.5	31.6	\$ 46.6	\$ 39.6	17.7	
Cost of gas sold	<u>3.1</u>	1.8	76.0	<u> 15.0</u>	<u> 10.4</u>	45.3	23.3	<u> 18.3</u>	27.0	
Gas operating revenues										
over cost of gas in rates										
(margin)	\$ 4.7	\$ 4.0	15.6	\$ 13.2	\$ 11.1	18.8	\$ 23.3	\$ 21.3	9.6	

The twelve month ended percentage change reflects the transfer of customers from industrial sales to transportation during the first quarter of 2012.

During the second quarter of 2013, gas segment revenues increased approximately \$2.0 million, mainly due to increased sales resulting from the cooler than normal weather previously discussed. Our gas gross margin (defined as gas operating revenues less cost of gas in rates) for the second quarter of 2013 increased \$0.7 million as compared to the second quarter of 2012 due to the weather impact.

⁽²⁾ Other includes other public authorities and interdepartmental usage.

⁽²⁾ Other includes other public authorities and interdepartmental usage.

During the six and twelve month periods ended June 30, 2013, gas segment revenues increased approximately \$6.7 million and \$7.0 million, respectively, as compared to the corresponding periods ended June 30, 2012 mainly due to increased sales resulting from colder weather during the first and second quarters of 2013 as compared to the same period in 2012. Our gas gross margin for the six and twelve months ended June 30, 2013 increased \$2.1 million and \$2.0 million, respectively, as compared to the corresponding 2012 periods.

We have a PGA clause in place that allows us to recover from our customers, subject to routine regulatory review, the cost of purchased gas supplies, transportation and storage, including costs associated with the use of financial instruments to hedge the purchase price of natural gas. Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA are reflected as a regulatory asset or regulatory liability until the balance is recovered from or credited to customers. As of June 30, 2013, we had unrecovered purchased gas costs of \$0.4 million recorded as a current regulatory asset and over recovered purchased gas costs \$0.7 million recorded as a non-current regulatory liability.

Operating Revenue Deductions

The table below shows regulated operating expense increases/(decreases) for the applicable periods ended June 30, 2013 as compared to the same periods in 2012.

	Three Months	Six Months	Twelve Months
	Ended	Ended	Ended
(in millions)	2013 vs. 2012	2013 vs. 2012	2013 vs. 2012
Transmission operation expense	\$ (0.1)	\$ (0.2)	\$ (0.3)
Customer assistance expense	0.0	0.0	(0.1)
TOTAL	\$ (0.1 <u>)</u>	\$ (0.2 <u>)</u>	\$ (0.4)

Our gas segment had a \$0.2 million net loss for the second quarter of 2013 as compared to a \$0.4 million net loss for the second quarter of 2012.

Our gas segment had net income of \$1.8 million for the six months ended June 30, 2013 and \$2.3 million for the twelve months ended June 30, 2013, as compared to \$0.7 million and \$1.2 million, respectively, for the comparable periods ended June 30, 2012.

Consolidated Company

Income Taxes

The following table shows the changes in our provision for income taxes (in millions) and our consolidated effective federal and state income tax rates for the applicable periods ended June 30:

	Three Month	ns Ended	Six Month	ns Ended	Twelve Mont	<u>hs Ended</u>
	2013	2012	2013	2012	2013	2012
Consolidated provision for income taxes	\$ 7.0	\$ 6.8	\$ 14.5	\$ 13.0	\$ 35.7	\$ 34.4
Consolidated effective federal and state						
income tax rates	37.7%	38.7%	37.4%	38.7%	37.5%	38.8%

See Note 12 of "Notes to Consolidated Financial Statements (Unaudited)" for more information and discussion concerning our income tax provision and effective tax rates.

Nonoperating Items

The following table shows the total allowance for funds used during construction (AFUDC) for the applicable periods ended June 30. AFUDC increased during all periods presented in 2013 reflecting the environmental retrofit project at our Asbury plant.

	<u>Thr</u>	Three Months Ended			Six Months Ended				Twe	Twelve Months Ende		
(\$ in millions)		<u> 2013</u>	2	012	2	2013		2012	2	2013	2	012
Allowance for equity funds used during			_		_				_			
construction	\$	8.0	\$	0.1	\$	1.4	\$	0.1	\$	2.4	\$	0.3
Allowance for borrowed funds used												
during construction		0.5		0.1		8.0		0.2		1.4		0.3
Total AFUDC	\$	1.3	\$	0.2	\$	2.2	\$	0.3	\$	3.8		0.6

Total interest charges on long-term and short-term debt for the periods ended June 30, are shown below. The changes in long-term debt interest for all periods reflect the financing discussed in Note 6 of "Notes to Consolidated Financial Statements (Unaudited)" and under "Liquidity and Capital Resources - Financing Activities" below. The change in the twelve months ended interest charges also reflects the redemption on April 1, 2012 of all \$74.8 million aggregate principal amount of our First Mortgage Bonds, 7.00% Series due 2024, the redemption of all \$5.2 million of our First Mortgage Bonds, 5.20% Pollution Control Series due 2013, and all \$8.0 million of our First Mortgage Bonds, 5.30% Pollution Control Series due 2013. These bonds were replaced by a private placement of \$88.0 million aggregate principal amount of 3.58% First Mortgage Bonds due April 2, 2027. The first settlement of \$38.0 million occurred on April 2, 2012 and the second settlement of \$50.0 million occurred on June 1, 2012. The changes in short-term debt interest primarily reflect lower levels of borrowing during the three months ended and six months ended periods and higher levels of borrowing during the twelve months ended period.

Interest Charges	5
(in millions)	

_	(in millions)								
	Second Second 6 Months 6 Months 12 M				12 Months	ıths			
	Quarter	Quarter	%	Ended	Ended	%	Ended	Ended	%
	2013	2012	Change*	2013	2012	Change*	2013	2012	Change*
Long-term debt interest	10.2	9.6	5.7%	20.2	20.3	(0.7)%	40.0	41.6	(3.7)%
Short-term debt interest	0.0	0.1	(91.1)	0.1	0.2	(63.1)	0.1	0.2	(56.5)
latan1and 2 carrying charges*	0.0	0.0	26.5	0.1	0.1	26.6	0.1	0.1	12.4
Other interest	0.3	0.3	0.3	0.4	0.4	(2.5)	<u>1.0</u>	<u>1.0</u>	0.2
Total interest charges	10.5	10.0	4.4	20.8	21.0	(1.2)	41.2	42.9	(3.9)

^{*}The twelve month ended comparison reflects deferred latan 1 and latan 2 carrying charges to reflect construction accounting in accordance with our agreement with the MPSC. Deferral ended when the plants were placed in rates. See Note 3 and Rate Matters below for additional information regarding carrying charges.

RATE MATTERS

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

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of utility plant or write-off's as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases since January 1, 2010:

		An	nual Increase	Percent Increase	
Jurisdiction	Date Requested		Granted	Granted	Date Effective
Missouri – Electric	July 6, 2012	\$	27,500,000	6.78%	April 1, 2013
Missouri – Water	May 21, 2012	\$	450,000	25.5%	November 23, 2012
Missouri – Electric	September 28, 2010	\$	18,700,000	4.70%	June 15, 2011
Missouri – Electric	October 29, 2009	\$	46,800,000	13.40%	September 10, 2010
Kansas – Electric	June 17, 2011	\$	1,250,000	5.20%	January 1, 2012
Kansas – Electric	November 4, 2009	\$	2,800,000	12.40%	July 1, 2010
Oklahoma – Electric	June 30, 2011	\$	240,722	1.66%	January 4, 2012
Oklahoma – Electric	January 28, 2011	\$	1,063,100	9.32%	March 1, 2011
Oklahoma – Electric	March 25, 2010	\$	1,456,979	15.70%	September 1, 2010
Arkansas - Electric	August 19, 2010	\$	2,104,321	19.00%	April 13, 2011
Missouri – Gas	June 5, 2009	\$	2,600,000	4.37%	April 1, 2010

On February 22, 2013, we filed a Nonunanimous Stipulation and Agreement (Agreement) with the MPSC which issued an order approving the Agreement on February 27, 2013, effective March 6, 2013. The Agreement provided for an annual increase in base revenues for our Missouri electric customers in the amount of approximately \$27.5 million, effective April 1, 2013, and the continuation of the current fuel adjustment mechanism. The Agreement also included an increase in depreciation rates, recovery of deferred tornado costs over the next ten years and the continuation of tracking mechanisms for expenses related to employee pension, retiree health care, vegetation management, and latan 2, latan Common and Plum Point operating and maintenance costs. In addition, the Agreement included a write-off of approximately \$3.6 million, consisting of a \$2.4 million disallowance for the prudency of certain construction expenditures for latan 2 and a \$1.2 million regulatory reversal of a prior period gain on sale of our Asbury unit train, which is included in regulated operating expenses. We also agreed not to implement a Missouri general rate increase prior to October 1, 2014.

As initially filed on July 6, 2012, we requested an annual increase in base rates for our Missouri electric customers in the amount of \$30.7 million, or 7.56%, and the continuation of the fuel adjustment clause. This request was primarily designed to recover operation and maintenance expenses and capital costs associated with the May 22, 2011 tornado, Southwest Power Pool transmission charges allocated to us, operating systems replacement costs for new software systems, vegetation management costs, new depreciation rates and amortization of a regulatory asset related to the tax benefits of cost of removal, the balance of which was approximately \$9.6 million at December 31, 2012.

On May 18, 2012, we filed a request with the FERC to implement a TFR to be effective August 1, 2012. On July 31, 2012, the FERC suspended the TFR for five months and set the filing for hearing and settlement procedures. On June 13, 2013, we, the Kansas Corporation Commission and the cities of Monett, Mt. Vernon and Lockwood, Missouri and Chetopa, Kansas, filed a unanimous Settlement Agreement (Agreement) with the FERC. The Agreement includes a TFR that establishes an ROE of 10.0%. The Agreement calls for the TFR to be updated annually with the new updated TFR rates effective on July 1 of each year. FERC action on the Agreement is pending.

Our other rate cases, as we reported in our Annual Report on Form 10-K for the year ended December 31, 2012, remain unchanged. See Note 3, "Regulatory Matters" in our Annual Report on Form 10-K for the year ended December 31, 2012 for additional information

COMPETITION AND MARKETS

Electric Segment

<u>SPP Regional Transmission Development:</u> On June 17, 2010, the FERC approved the new highway/byway cost allocation method, a new transmission cost allocation method to replace the existing FERC accepted cost allocation method for new transmission facilities needed to continue to reliably and economically serve Southwest Power Pool (SPP) customers, including ours, well into the future. To date, the SPP's Board of Directors (BOD) has approved over \$8 billion in transmission projects for the 2006 through 2022 time period of which over \$4 billion is in planned highway/byway

transmission projects. As these projects are constructed, we will be allocated a share of the costs of the projects pursuant to the FERC accepted highway/byway regional costs allocation method. We expect that these operating costs will be material, but that they will be recoverable in future rates.

Other FERC Activity

On April 23, 2012, we intervened in the SPP's Petition for Review (Case No. 12-1158) of FERC's Orders on Declaratory Order and Rehearing (Docket No. EL11-34-000) on the interpretation of the SPP/MISO Joint Operating Agreement (JOA) at the United States Court of Appeals for the District of Columbia. We are in agreement with SPP and other SPP members that FERC was incorrect in its determination that MISO's interpretation of the Joint Operating Agreement appropriately enables MISO and Entergy to utilize ours and other SPP members transmission systems to integrate Entergy into the MISO RTO without compensation or consideration of the negative impacts to us and the other SPP members. On June 25, 2012, the SPP interveners made a joint intervention filing at the DC court and a joint brief in October 2012 and reply brief on January 14, 2013. It is in our best interests that the review of the Joint Operating Agreement between SPP and MISO be remanded back to FERC to reevaluate its Orders. Based on the current terms and conditions of MISO membership, Entergy's participation in MISO will not be beneficial to our customers as it will increase transmission delivery costs for our Plum Point power station as well as utilize our transmission system without compensation. In late 2012, ITC Holdings and Entergy announced the sale of transmission assets to ITC and formation of new ITC transmission only companies. Subsequently, ITC, Entergy, and MISO made multiple filings at the FERC for the transfer of ownership of Entergy's transmission facilities as well as full integration into the MISO RTO. We and several other SPP members jointly filed in protest of the filings on January 11, 2013, based on Entergy and MISO's planned utilization of our and the other SPP members' system without mitigation or resolution of the current and expected harm of MISO's interpretation/use of the joint operating agreement to implement the integration. On June 20, 2013, FERC issued several Orders, with some conditions, approving Entergy joining MISO and the purchase of Entergy transmission assets by a newly created subsidiary of ITC Holdings, ITC South. Many of the SPP joint protestors will be making a joint filing at FERC for clarification and/or rehearing of FERC's orders on ITC/Entergy/MISO with an emphasis on FERC's lack of requirement for SPP and MISO to resolve their JOA issues of dispute prior to Entergy joining MISO in late December 2013.

We and several other SPP members have intervened at the Missouri and Arkansas commissions in opposition to the sale/transfer of transmission assets of Entergy Arkansas to ITC South. We believe the sale of Entergy's transmission facilities and joining MISO has not been shown to be in the public interest and will negatively impact and increase cost to our customers. Those transfer of transmission asset cases are pending before those commissions with rulings expected in early fall 2013. The transaction between ITC and Entergy is conditional upon Entergy securing all necessary state and federal regulatory approvals.

See Note 3, "Regulatory Matters - Competition" in our Annual Report on Form 10-K for the year ended December 31, 2012 for additional information.

LIQUIDITY AND CAPITAL RESOURCES

Overview. Our primary sources of liquidity are cash provided by operating activities, short-term borrowings under our commercial paper program (which is supported by our credit facilities) and borrowings from our unsecured revolving credit facility. As needed, we raise funds from the debt and equity capital markets to fund our liquidity and capital resource needs.

Our issuance of various securities, including equity, long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. We estimate that internally generated funds (funds provided by operating activities less dividends paid) will provide approximately 66% of the funds required for the remainder of our budgeted 2013 capital expenditures (as discussed in "Capital Requirements and Investing Activities" below). We believe the amounts available to us under our credit facilities and the

issuance of debt and equity securities together with this cash provided by operating activities, will allow us to meet our needs for working capital, pension contributions, our continuing construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the timing of our construction programs and other factors. See Item 1A, "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2012 for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities for the six months ended June 30:

Summary of Cash Flows

	Six Months Ended June 30,			
(in millions)	<u>2013</u>	<u>2012</u>	<u>Change</u>	
Cash provided by/(used in):				
Operating activities	\$ 71.0	\$ 71.7	\$ (0.7)	
Investing activities	(73.2)	(62.3)	(10.9)	
Financing activities	9.7	(12.0)	21.7	
Net change in cash and cash equivalents	\$ 7.5	\$ (2.6)	\$ 10.1	

Cash flow from Operating Activities

We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, pension costs, deferred income taxes, equity AFUDC, changes in commodity risk management assets and liabilities and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

Period-over-period changes in our operating cash flows are attributable primarily to working capital changes resulting from the impact of weather, the timing of customer collections, payments for natural gas and coal purchases, the effects of deferred fuel recoveries and the size and timing of pension contributions. The increase or decrease in natural gas prices directly impacts the cost of gas stored in inventory.

<u>Six Months Ended June 30, 2013 Compared to 2012</u>. During the six months ended June 30, 2013, our net cash flows provided from operating activities decreased \$0.7 million or 0.9% from 2012. This change resulted primarily from the following:

- Increase in net income \$3.8 million.
- Change in pension contributions net of expense accruals \$6.0 million.
- Non-cash loss on regulatory plant disallowance as a result of our 2013 Missouri electric rate case- \$2.4 million.
- Regulatory reversal of a prior period gain on the sale of assets as a result of our 2013 Missouri electric rate case \$1.2 million.
- Changes related to fuel inventories for both electric and gas segments \$5.8 million.
- 2012 asset retirement obligation adjustments \$0.9 million.
- Tax timing differences mostly related to depreciation and amortizations \$(1.4) million.
- Increase in equity AFUDC mostly attributable to higher construction work in progress balances
 \$(1.3) million.
- Lower fuel related amortizations partially offset by increased plant in service depreciation \$(5.3) million.
- Increase in customer accounts receivable \$(7.7) million.
- Increased change in fuel adjustment balances \$(5.2) million.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities increased \$10.9 million during the six months ended June 30, 2013 as compared to the same period in 2012.

Our capital expenditures incurred totaled approximately \$76.2 million during the six months ended June 30, 2013 compared to \$70.0 million for the six months ended June 30, 2012. The increase was primarily the result of an increase in electric plant additions and replacements, mainly due to the environmental retrofit in progress at our Asbury plant.

A breakdown of the capital expenditures for the six months ended June 30, 2013 and 2012 is as follows:

	Capital Expenditures			
(in millions)	2013	2012		
Distribution and transmission system additions	\$ 27.0	\$ 26.2		
New Generation – latan 2	0.2	1.0		
Additions and replacements – electric plant	40.2	21.2		
Storms	0.2	7.1		
Transportation	0.4	0.4		
Gas segment additions and replacements	2.1	1.4		
Other (including retirements and salvage -net) (1)	5.2	11.1		
Subtotal	75.3	68.4		
Non-regulated capital expenditures (primarily fiber optics)	0.9	1.6		
Subtotal capital expenditures incurred (2)	76.2	70.0		
Adjusted for capital expenditures payable (3)	(0.4)	(7.7)		
Total cash outlay	\$ 75.8	\$ 62.3		

⁽¹⁾ Other includes equity AFUDC of \$(1,4) million and \$(0,1) million for 2013 and 2012, respectively.

Approximately 42% of our cash requirements for capital expenditures during the second quarter of 2013 were satisfied from internally generated funds (funds provided by operating activities less dividends paid).

We estimate that internally generated funds will provide approximately 66% of the funds required for the remainder of our budgeted 2013 capital expenditures. We intend to utilize short-term debt to finance any additional amounts needed beyond those provided by operating activities for such capital expenditures. If additional financing is needed, we intend to utilize a combination of debt and equity securities. For further information see Note 6 of "Notes to Consolidated Financial Statements (Unaudited)."

Financing Activities

Six Months Ended June 30, 2013 Compared to Six months Ended June 30, 2012.

Our net cash flows provided by financing activities was \$9.7 million in the six months ended June 30, 2013, an increase of \$21.7 million as compared to a \$12.0 million use of cash during the six months ended June 30, 2012, primarily due to the following:

- Issuance of \$150.0 million of first mortgage bonds in the six months ended June 30, 2013 compared to \$88.0 million in the six months ended June 30, 2012
- Repayment of \$98.0 million of senior notes in the six months ended June 30, 2013 compared to \$88.0 million of first mortgage bonds in the six months ended June 30, 2012.
- Repayment of \$24.0 million in short-term debt in the six months ended June 30, 2013 as compared to borrowing \$5.9 million in the six months ended June 30, 2012.

⁽²⁾ Expenditures incurred represent the total cost for work completed for the projects during the reporting period. Discussion of capital expenditures throughout this 10-Q is presented on this basis. These capital expenditures include AFUDC, capital expenditures to retire assets and benefits from salvage.

⁽³⁾ The amount of expenditures paid/(unpaid) at the end of the reporting period to adjust to actual cash outlay reflected in the Investing Activities section of the Statement of Cash Flows.

See the financing discussion in Note 6 of "Notes to Consolidated Financial Statements (Unaudited)."

Shelf Registration

We have a \$400.0 million shelf registration statement with the SEC, effective for a three-year period beginning February 7, 2011, covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. We have received regulatory approval for the issuance of securities under this shelf from all four states in our electric service territory, but we may only issue up to \$250.0 million of such securities in the form of first mortgage bonds, of which \$12.0 million remains available after giving effect to the \$150.0 million of new first mortgage bonds issued on May 30, 2013. We plan to use proceeds from offerings made pursuant to this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs.

Credit Agreements

On January 17, 2012, we entered into the Third Amended and Restated Unsecured Credit Agreement which amended and restated our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. This agreement extended the termination date of the revolving credit facility from January 26, 2013 to January 17, 2017. The agreement also removed the letter of credit facility and includes a swingline loan facility with a \$15 million swingline loan sublimit. The aggregate amount of the revolving credit commitments remains \$150 million, inclusive of the \$15 million swingline loan sublimit. In addition, the pricing and fees under the facility were amended. Interest on borrowings under the facility accrues at a rate equal to, at our option, (i) the highest of (A) the bank's prime commercial rate, (B) the federal funds effective rate plus 0.5% or (C) one month LIBOR plus 1.0%, plus a margin or (ii) one month, two month or three month LIBOR, in each case, plus a margin. Each margin is based on our current credit ratings and the pricing schedule in the facility. As of the date hereof, and based on our current credit ratings, the LIBOR margin under the facility is 1.25%. A facility fee is payable quarterly on the full amount of the commitments under the facility based on our current credit ratings, which fee is currently 0.25%. In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of \$262,500 in the aggregate. There were no other material changes to the terms of the facility.

The facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness 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 and amortization) to be at least two times our interest charges 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. As of June 30, 2013, we are in compliance with these ratios. Our total indebtedness is 50.6% of our total capitalization as of June 30, 2013 and our EBITDA is 5.0 times our interest charges. This credit facility is also subject to cross-default if we default on in excess of \$10 million in the aggregate on our other indebtedness. This arrangement does not serve to legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under this agreement at June 30, 2013 and no outstanding commercial paper.

EDE Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to \$1.0 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE 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 June 30, 2013 would permit us to

issue approximately \$530.9 million of new first mortgage bonds based on this test with an assumed interest rate of 5.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At June 30, 2013, we had retired bonds and net property additions which would enable the issuance of at least \$812.7 million principal amount of bonds if the annual interest requirements are met. As of June 30, 2013, we are in compliance with all restrictive covenants of the EDE Mortgage.

EDG Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to \$300.0 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1.0. As of June 30, 2013, this test would allow us to issue approximately \$14.3 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%.

Currently, our corporate credit ratings and the ratings for our securities are as follows:

	Fitch	Moody's	Standard & Poor's
Corporate Credit Rating	n/r*	Baa2	BBB
EDE First Mortgage Bonds	BBB+	A3	A-
Senior Notes	BBB	Baa2	BBB
Commercial Paper	F3	P-2	A-2
Outlook	Stable	Stable	Stable
*Not rated			

On March 6, 2013, Standard & Poor's upgraded our corporate credit rating to BBB from BBB-, senior secured debt to A- from BBB+, senior unsecured debt to BBB from BBB- and our commercial paper rating to A-2 from A-3. Standard & Poor's outlook for Empire is stable. On May 26, 2011 after the May 22, 2011 tornado, and again on April 25, 2012, Moody's reaffirmed all of our ratings. On March 24, 2011, Fitch revised our commercial paper rating from F2 to F3 and reaffirmed our other ratings. The rating action was not based on a specific action or event on our part, but reflected their traditional linkage of long-term and short-term Issuer Default Ratings. On May 24, 2013, Fitch reaffirmed our ratings.

A security rating is not a recommendation to buy, sell or hold securities. Each rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered independently of all other ratings.

CONTRACTUAL OBLIGATIONS

Material changes to our contractual obligations at June 30, 2013, compared to December 31, 2012, consist of the following:

- On October 30, 2012, we entered into a Bond Purchase Agreement for a private placement of \$30.0 million of 3.73% First Mortgage Bonds due May 30, 2033 and \$120.0 million of 4.32% First Mortgage Bonds due May 30, 2043. The delayed settlement of both series of bonds occurred on May 30, 2013.
- On June 15, 2013, we redeemed all \$98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013.
 - See "Financing Activities" above for details.

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). A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

In response to the expected loss of revenues resulting from the May 22, 2011 tornado, our level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 2012, the Board of Directors reestablished the dividend and declared a quarterly dividend of \$0.25 per share on common stock payable on March 15, 2012 to holders of record as of March 1, 2012. Dividends were paid during all four quarters of 2012. As of June 30, 2013, our retained earnings balance was \$50.1 million, compared to \$33.1 million as of June 30, 2012 and \$47.1 million as of December 31, 2012. On July 25, 2013, the Board of Directors declared a quarterly dividend of \$0.25 per share on common stock payable September 16, 2013 to holders of record as of September 3, 2013.

Our diluted earnings per share were \$0.57 for the six months ended June 30, 2013 and were \$1.32 and \$1.31 for the years ended December 31, 2012 and 2011, respectively. Dividends paid per share were \$0.50 for the six months ended June 30, 2013, \$1.00 for the year ended December 31, 2012 and \$0.64 for the year ended December 31, 2011.

Under Kansas corporate law, our Board of Directors may only declare and pay dividends out of our surplus or, if there is no surplus, out of our net profits for the fiscal year in which the dividend is declared or the preceding fiscal year, or both. Our surplus, under Kansas law, is equal to our retained earnings plus accumulated other comprehensive income/(loss), net of income tax. However, Kansas law does permit, under certain circumstances, our Board of Directors to transfer amounts from capital in excess of par value to surplus. In addition, Section 305(a) of the Federal Power Act (FPA) prohibits the payment by a utility of dividends from any funds "properly included in capital account". There are no additional rules or regulations issued by the FERC under the FPA clarifying the meaning of this limitation. However, several decisions by the FERC on specific dividend proposals suggest that any determination would be based on a fact-intensive analysis of the specific facts and circumstances surrounding the utility and the dividend in question, with particular focus on the impact of the proposed dividend on the liquidity and financial condition of the utility.

In addition, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE 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 sum of \$10.75 million and the earned surplus (as defined in the EDE 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. The EDE Mortgage permits the payment of any dividend or distribution on, or purchase of, shares of our common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

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, other than operating leases entered into in the normal course of business.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2012 for a discussion of additional critical accounting policies. There were no changes in these policies in the quarter ended June 30, 2013.

RECENTLY ISSUED ACCOUNTING STANDARDS

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our fuel procurement activities involve primary market risk exposures, including commodity price risk and credit risk. Commodity price risk is the potential adverse price impact related to the fuel procurement for our generating units. Credit risk is the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. Additionally, we are exposed to interest rate risk which is the potential adverse financial impact related to changes in interest rates.

Market Risk and Hedging Activities.

Prices in the wholesale power markets often are extremely volatile. This volatility impacts our cost of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our customers, we would attempt to purchase power from others. Such supplies are not always available. In addition, congestion on the transmission system can limit our ability to make purchases from (or sell into) the wholesale markets.

We engage in physical and financial trading activities with the goals of reducing risk from market fluctuations. In accordance with our established Energy Risk Management Policy, which typically includes entering into various derivative transactions, we attempt to mitigate our commodity market risk. Derivatives are utilized 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 4 of "Notes to Consolidated Financial Statements (Unaudited)" for further information.

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 65.6% of our 2012 generation fuel supply need through coal. This includes the remaining coal used at Riverton as part of its transition to natural gas. Approximately 96% of our 2012 coal supply was Western coal. We have contracts and binding proposals to supply a portion of the fuel for our coal plants through 2015. These contracts satisfy approximately 100% of our anticipated fuel requirements for 2013, 58% for 2014 and 26% for our 2015 requirements for our Asbury coal plant. 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 manage our costs to avoid 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 expenditures and improve predictability. As of June 30, 2013, 64%, or 3.8 million Dths's, of our anticipated volume of natural gas usage for our electric operations for the remainder of 2013 is hedged.

Based on our expected natural gas purchases for our electric operations for the next twelve months, if average natural gas prices should increase 10% more than the price at June 30, 2013, our natural gas cost would increase by approximately \$1.4 million based on our June 30, 2013 total hedged positions for the next twelve months. However, this is probable of recovery through fuel adjustment mechanisms in all of our jurisdictions, which significantly reduces the impact of fluctuating fuel costs.

We attempt to mitigate a portion of our natural gas price risk associated with our gas segment using physical forward purchase agreements, storage and derivative contracts. As of June 30, 2013, we have 0.8 million Dths in storage on the three pipelines that serve our customers. This represents 38% of our storage capacity.

See Note 4 of "Notes to Consolidated Financial Statements (Unaudited)" for further information.

Credit Risk.

In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. See Note 4 of "Notes to Consolidated Financial Statements (Unaudited)" regarding agreements containing credit risk contingent features. In addition, certain counterparties make available collateral in the form of cash held as margin deposits as a result of exceeding agreed-upon credit exposure thresholds or may be required to prepay the transaction. Conversely, we are required to post collateral with counterparties at certain thresholds, which is typically the result of changes in commodity prices. Amounts reported as margin deposit liabilities represent counterparty funds we hold that result from various trading counterparties exceeding agreed-upon credit exposure thresholds. Amounts reported as margin deposit assets represent our funds held on deposit for our NYMEX contracts with our broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at June 30, 2013 and December 31, 2012. There were no margin deposit liabilities at these dates.

	June 30, 2013	December 31, 2012
(in millions)		
Margin deposit assets	\$ 5.0	\$ 4.2

Our exposure to credit risk is concentrated primarily within our fuel procurement process, as we transact with a small group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Below is a table showing our net credit exposure at June 30, 2013, reflecting that our counterparties are exposed to Empire for the net unrealized mark-to-market losses for physical forward and financial natural gas contracts carried at fair value.

(in millions)

Net unrealized mark-to-market losses for physical forward natural gas contracts

Net unrealized mark-to-market losses for financial natural gas contracts

Net credit exposure

4.2

6.8

11.0

The \$6.8 million net unrealized mark-to-market loss for financial natural gas contracts is comprised of \$6.8 million that our counterparties are exposed to Empire for unrealized losses. We are holding no collateral from any counterparty since they are below the \$10.0 million mark-to-market collateral threshold in our agreements. As noted above, as of June 30, 2013, we have \$5.0 million on deposit for NYMEX contract exposure to Empire, of which \$4.9 million represents our collateral requirement. In addition, if NYMEX gas prices decreased 25% from their June 30, 2013 levels, we would be required to post an additional \$10.7 million in collateral. If these prices increased 25%, our collateral requirement would decrease \$3.4 million. Our other counterparties would not be required to post collateral with Empire.

We sell electricity and gas and provide distribution and transmission services to a diverse group of customers, including residential, commercial and industrial customers. Credit risk associated with trade accounts receivable from energy customers is limited due to the large number of

customers. In addition, we enter into contracts with various companies in the energy industry for purchases of energy-related commodities, including natural gas in our fuel procurement process.

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 2013 than in 2012, our interest expense would increase, and income before taxes would decrease by less than \$0.6 million. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2012. 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.

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 (as such term is defined in Rule 13a-15(e) 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 as of June 30, 2013.

There have been no changes in our internal control over financial reporting that occurred during the second quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

See Note 7 of "Notes to Consolidated Financial Statements (Unaudited)" under "Legal Proceedings", which description is incorporated herein by reference.

Item 1A. Risk Factors.

There have been no material changes to the factors disclosed in Part I, Item 1-A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012.

Item 5. Other Information.

For the twelve months ended June 30, 2013, our ratio of earnings to fixed charges was 2.94x. See Exhibit (12) hereto.

Item 6. Exhibits.

(a) Exhibits.

- (4) Thirty-Ninth Supplemental Indenture, dated May 30, 2013, to the Indenture of Mortgage and Deed of Trust dated as of September 1, 1944, as amended and supplemented, by and among the Company, The Bank of New York Mellon Trust Company, N.A. and UMB Bank & Trust, N. A. (Incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K dated May 30, 2013 and filed May 30, 2013, File No. 001-03368).
- (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.*
- (101) The following financial information from The Empire District Electric Company's Quarterly Report on Form 10-Q for the period ended June 30, 2013, filed with the SEC on August 7, 2013, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income for the three, six and twelve month periods ended June 30, 2013 and 2012, (ii) the Consolidated Balance Sheets at June 30, 2013 and December 31, 2012, (iii) the Consolidated Statements of Cash Flows for the six-month periods ended June 30, 2013 and 2012, and (iv) Notes to Consolidated Financial Statements.**

*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.

**Pursuant to Rule 406T of Regulation S-T, the XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall not be deemed to be "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be deemed incorporated by reference into, or part of a registration statement, prospectus or other document filed under the Securities Act of 1933, as amended or the Exchange Act of 1934, as amended except as shall be expressly set forth by specific reference in such filings.

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/ Laurie A. Delano
-	Laurie A. Delano
	Vice President – Finance and Chief Financial Officer
By_	/s/ Robert W. Sager
	Robert W. Sager
	Controller, Assistant Secretary and Assistant Treasurer

August 7, 2013

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Twelve Months Ended June 30, 2013		
Income before provision for income taxes and fixed charges (Note A)	\$	144,156,576	
Fixed charges: Interest on long-term debt Interest on short-term debt Other interest Rental expense representative of an interest factor (Note B)	\$	40,041,915 86,681 1,091,560 7,750,400	
Total fixed charges	\$	48,970,556	
Ratio of earnings to fixed charges		2.94x	

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, and by the sum of fixed charges as shown above.

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

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

- I, Bradley P.Beecher, 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 periods 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 15d-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;
 - 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 (the registrant's fourth fiscal quarter in the case of an annual report) 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 the registrant's board of directors (or persons performing the equivalent functions):
 - 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: August 7, 2013

By: /s/ Bradley P. Beecher

Name: Bradley P.Beecher

Title: President and Chief Executive Officer

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

I, Laurie A. Delano, 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 periods 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 15d-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;
 - 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 (the registrant's fourth fiscal quarter in the case of an annual report) 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 the registrant's board of directors (or persons performing the equivalent functions):
 - 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: August 7, 2013

By: /s/ Laurie A. Delano

Name: Laurie A. Delano

Title: Vice President - Finance and Chief Financial Officer

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 June 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Bradley P. Beecher, 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 /s/ Bradley P. Beecher

Name: Bradley P. Beecher

Title: President and Chief Executive Officer

Date: August 7, 2013

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.

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 June 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Laurie A. Delano, 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/ Laurie A. Delano

Name: Laurie A. Delano

Title: Vice President - Finance and Chief Financial Officer

Date: August 7, 2013

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.