OGE ENERGY CORP.
Form 10-Q
August 02, 2012

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

FORM 10-Q

(Mark One)
S QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2012

OR

£ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number: 1-12579
OGE ENERGY CORP.
(Exact name of registrant as specified in its charter)

Oklahoma	73-1481638
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)

405-553-3000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). R Yes £ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer R	Accelerated filer £
Non-accelerated filer £ (Do not check if a smaller reporting company)	Smaller reporting company £

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

At June 30, 2012, there were 98,656,135 shares of common stock, par value $0.01 per share, outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED JUNE 30, 2012

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GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations that are found throughout this Form 10-Q.

Abbreviation	Definition
2011 Form 10-K	Annual Report on Form 10-K for the year ended December 31, 2011
APSC	Arkansas Public Service Commission
ArcLight group	Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, collectively
Atoka	Atoka Midstream LLC joint venture
BART	Best available retrofit technology
Chesapeake	Chesapeake Energy Marketing, Inc. and Chesapeake Exploration, L.L.C.
Company	OGE Energy, collectively with its subsidiaries
Dry Scrubbers	Dry flue gas desulfurization units with spray dryer absorber
EBITDA	Enogex Holdings earnings before interest, taxes, depreciation and amortization
Enogex	OGE Holdings, collectively with its subsidiaries
Enogex LLC	Enogex LLC, collectively with its subsidiaries
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIP	Federal implementation plan
GAAP	Accounting principles generally accepted in the United States
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
NGLs	Natural gas liquids
NOX	Nitrogen oxide
NYMEX	New York Mercantile Exchange
OCC	Oklahoma Corporation Commission
OER	OGE Energy Resources LLC, wholly-owned subsidiary of Enogex LLC (subsequent to June 30, 2012, the legal name has been changed to Enogex Energy Resources LLC)
Off-system sales	Sales to other utilities and power marketers
OG&E	Oklahoma Gas and Electric Company
OGE Holdings	OGE Enogex Holdings, LLC, wholly-owned subsidiary of OGE Energy and parent company of Enogex Holdings
Pension Plan	Qualified defined benefit retirement plan
PRM	Price risk management
SIP	State implementation plan
SO2	Sulfur dioxide
SPP	Southwest Power Pool
System sales	Sales to OG&E's customers
TBtu/d	Trillion British thermal units per day

FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Form 10-Q, including those matters discussed in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may vary materially from those expressed in forward-looking statements. In addition to the specific risk factors discussed in "Item 1A. Risk Factors" in the Company's 2011 Form 10-K and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of the Company and its subsidiaries to access the capital markets and obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and NGLs, each on a stand-alone basis and in relation to each other as well as the processing contract mix between percent-of-liquids, percent-of-proceeds, keep-whole and fixed-fee;
- business conditions in the energy and natural gas midstream industries;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- unusual weather;
- availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets;
- environmental laws and regulations that may impact the Company's operations;
- changes in accounting standards, rules or guidelines;
- the discontinuance of accounting principles for certain types of rate-regulated activities;
- whether OG&E can successfully implement its Smart Grid program to install meters for its customers and integrate the Smart Grid meters with its customer billing and other computer information systems;
- the cost of protecting assets against, or damage due to, terrorism or cyber attacks and other catastrophic events;
- advances in technology;
- creditworthiness of suppliers, customers and other contractual parties;
- the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including those listed in "Item 1A. Risk Factors" and in Exhibit 99.01 to the Company's 2011 Form 10-K.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions except per share data)	2012	2011	2012	2011
OPERATING REVENUES				
Electric Utility operating revenues	$528.0	$568.7	$954.7	$990.8
Natural Gas Midstream Operations operating revenues	327.0	409.4	741.0	827.8
Total operating revenues	855.0	978.1	1,695.7	1,818.6
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)				
Electric Utility cost of goods sold	192.7	242.5	376.3	450.0
Natural Gas Midstream Operations cost of goods sold	216.6	307.6	518.3	633.3
Total cost of goods sold	409.3	550.1	894.6	1,083.3
Gross margin on revenues	445.7	428.0	801.1	735.3
OPERATING EXPENSES				
Other operation and maintenance	153.0	146.6	300.6	284.9
Depreciation and amortization	90.5	74.7	177.1	148.7
Impairment of assets	0.1	—	0.3	—
Gain on insurance proceeds	—	—	(7.5)	—
Taxes other than income	24.8	24.5	55.0	51.6
Total operating expenses	268.4	245.8	525.5	485.2
OPERATING INCOME	177.3	182.2	275.6	250.1
OTHER INCOME (EXPENSE)				
Interest income	0.1	0.1	0.1	0.2
Allowance for equity funds used during construction	1.7	5.8	3.6	10.2
Other income	2.4	7.0	10.1	13.3
Other expense	(3.6)	(3.5)	(5.5)	(5.8)
Net other income	0.6	9.4	8.3	17.9
INTEREST EXPENSE				
Interest on long-term debt	38.9	35.8	78.1	71.2
Allowance for borrowed funds used during construction	(0.9)	(2.9)	(2.0)	(5.2)
Interest on short-term debt and other interest charges	2.4	1.6	4.4	2.6
Interest expense	40.4	34.5	80.5	68.6
INCOME BEFORE TAXES	137.5	157.1	203.4	199.4
INCOME TAX EXPENSE	35.9	47.8	54.3	60.4
NET INCOME	101.6	109.3	149.1	139.0
Less: Net income attributable to noncontrolling interests	7.7	6.3	18.1	11.2
NET INCOME ATTRIBUTABLE TO OGE ENERGY	$93.9	$103.0	$131.0	$127.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	98.6	98.0	98.4	97.8
DILUTED AVERAGE COMMON SHARES OUTSTANDING	98.9	99.3	98.8	99.2
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$0.95	$1.05	$1.33	$1.31
	$0.95	$1.04	$1.33	$1.29

DILUTED EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS				
DIVIDENDS DECLARED PER COMMON SHARE	$0.3925	$0.3750	$0.7850	$0.7500

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2012	2011	2012	2011
Net income	$101.6	$109.3	$149.1	$139.0
Other comprehensive income (loss), net of tax				
Pension Plan and Restoration of Retirement Income Plan:				
Amortization of deferred net loss, net of tax of $0.5 million, $0.5 million, $0.9 million and $0.9 million, respectively	0.7	0.5	1.5	1.0
Amortization of prior service cost, net of tax of $0.1 million, ($0.1) million, $0.1 million and $0, respectively	0.1	—	0.1	0.2
Postretirement plans:				
Amortization of deferred net loss, net of tax of $0.3 million, $0.1 million, $0.6 million and $0.6 million, respectively	0.5	0.6	1.0	0.8
Amortization of deferred net transition obligation, net of tax of $0, ($0.1) million, $0 and $0, respectively	—	—	—	0.1
Amortization of prior service cost, net of tax of ($0.2) million, ($0.3) million, ($0.5) million and ($0.6) million, respectively	(0.4)	(0.3)	(0.9)	(0.9)
Prior service credit arising during the period, net of tax of $0, $0, $0 and $6.2 million, respectively	—	—	—	10.7
Deferred commodity contracts hedging (gains) losses reclassified in net income, net of tax of $0, $3.4 million, ($1.7) million and $6.6 million, respectively	—	7.3	(3.3)	13.9
Deferred commodity contracts hedging losses, net of tax of ($0.2) million, ($0.5) million, ($0.2) million and ($2.5) million, respectively	(0.3)	(1.8)	(0.3)	(6.9)
Deferred interest rate swaps hedging losses reclassified in net income, net of tax of $0, $0, $0.1 million and $0.1 million, respectively	—	0.1	0.1	0.2
Other comprehensive income (loss), net of tax	0.6	6.4	(1.8)	19.1
Comprehensive income (loss)	102.2	115.7	147.3	158.1
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	—	—	—	(1.7)
Less: Comprehensive income attributable to noncontrolling interests	7.7	7.5	17.2	13.5
Total comprehensive income attributable to OGE Energy	$94.5	$108.2	$130.1	$146.3

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

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OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(In millions)	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$149.1	$139.0
Adjustments to reconcile net income to net cash provided from operating activities		
Depreciation and amortization	177.1	148.7
Impairment of assets	0.3	—
Deferred income taxes and investment tax credits, net	63.1	60.3
Allowance for equity funds used during construction	(3.6)	(10.2)
(Gain) loss on disposition and abandonment of assets	0.7	(3.3)
Gain on insurance proceeds	(7.5)	—
Stock-based compensation	(9.4)	0.4
Price risk management assets	2.8	1.1
Price risk management liabilities	(5.4)	6.8
Regulatory assets	10.3	6.8
Regulatory liabilities	(7.6)	3.3
Other assets	4.8	5.4
Other liabilities	(26.6)	(38.3)
Change in certain current assets and liabilities		
Accounts receivable, net	19.9	(47.0)
Accrued unbilled revenues	(25.3)	(39.8)
Income taxes receivable	(8.8)	—
Fuel, materials and supplies inventories	(3.6)	33.9
Gas imbalance assets	(8.3)	(3.6)
Fuel clause under recoveries	1.1	(21.4)
Other current assets	(13.0)	3.5
Accounts payable	(92.6)	(6.1)
Gas imbalance liabilities	(8.3)	1.0
Fuel clause over recoveries	57.7	(20.6)
Other current liabilities	14.6	26.6
Net Cash Provided from Operating Activities	281.5	246.5
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures (less allowance for equity funds used during construction)	(558.5)	(571.8)
Reimbursement of capital expenditures	23.4	21.6
Proceeds from insurance	7.6	—
Proceeds from sale of assets	0.6	17.5
Net Cash Used in Investing Activities	(526.9)	(532.7)
CASH FLOWS FROM FINANCING ACTIVITIES		
Increase in short-term debt	319.6	66.1
Issuance of common stock	7.0	7.5
Contributions from noncontrolling interest partners	1.0	73.5
Proceeds from long-term debt	—	246.3
Repayment of line of credit	—	(25.0)
Distributions to noncontrolling interest partners	(8.0)	(6.1)
Dividends paid on common stock	(77.1)	(73.3)

Net Cash Provided from Financing Activities	242.5	289.0
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(2.9)	2.8
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4.6	2.3
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$1.7	$5.1

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$1.7	$4.6
Accounts receivable, less reserve of $1.5 and $3.8, respectively	302.6	322.5
Accrued unbilled revenues	84.6	59.3
Income taxes receivable	17.1	8.3
Fuel inventories	101.1	100.7
Materials and supplies, at average cost	90.4	87.2
Price risk management	0.9	3.5
Gas imbalances	10.1	1.8
Deferred income taxes	74.7	32.1
Fuel clause under recoveries	0.7	1.8
Other	43.9	30.9
Total current assets	727.8	652.7
OTHER PROPERTY AND INVESTMENTS, at cost	48.8	46.7
PROPERTY, PLANT AND EQUIPMENT		
In service	10,956.3	10,315.9
Construction work in progress	363.1	499.0
Total property, plant and equipment	11,319.4	10,814.9
Less accumulated depreciation	3,455.7	3,340.9
Net property, plant and equipment	7,863.7	7,474.0
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	494.1	507.9
Intangible assets, net	132.2	137.0
Goodwill	39.4	39.4
Price risk management	0.1	0.3
Other	45.3	48.0
Total deferred charges and other assets	711.1	732.6
TOTAL ASSETS	$9,351.4	$8,906.0

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$596.7	$277.1
Accounts payable	274.5	388.0
Dividends payable	38.7	38.5
Customer deposits	69.4	67.6
Accrued taxes	45.7	42.3
Accrued interest	54.8	54.8
Accrued compensation	37.2	47.8
Price risk management	0.4	0.4
Gas imbalances	1.5	9.8
Fuel clause over recoveries	65.4	7.7
Other	84.5	64.5
Total current liabilities	1,268.8	998.5
LONG-TERM DEBT	2,737.5	2,737.1
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	334.1	360.8
Deferred income taxes	1,757.2	1,651.4
Deferred investment tax credits	5.0	6.1
Regulatory liabilities	242.5	230.7
Deferred revenues	40.5	40.8
Price risk management	—	0.1
Other	87.6	61.2
Total deferred credits and other liabilities	2,466.9	2,351.1
Total liabilities	6,473.2	6,086.7
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	1,028.2	1,035.3
Retained earnings	1,628.4	1,574.8
Accumulated other comprehensive loss, net of tax	(41.5)	(40.6)
Treasury stock, at cost	(0.1)	(6.2)
Total OGE Energy stockholders' equity	2,615.0	2,563.3
Noncontrolling interests	263.2	256.0
Total stockholders' equity	2,878.2	2,819.3
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$9,351.4	$8,906.0

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Premium on Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Treasury Stock	Total
Balance at December 31, 2011	$1.0	$1,034.3	$1,574.8	$(40.6)	$256.0	$(6.2)	$2,819.3
Comprehensive income (loss)							
Net income	—	—	131.0	—	18.1	—	149.1
Other comprehensive income (loss), net of tax	—	—	—	(0.9)	(0.9)	—	(1.8)
Comprehensive income (loss)	—	—	131.0	(0.9)	17.2	—	147.3
Dividends declared on common stock	—	—	(77.4)	—	—	—	(77.4)
Issuance of common stock	—	7.0	—	—	—	—	7.0
Stock-based compensation and other	—	(14.1)	—	—	(3.0)	6.1	(11.0)
Contributions from noncontrolling interest partners	—	—	—	—	1.0	—	1.0
Distributions to noncontrolling interest partners	—	—	—	—	(8.0)	—	(8.0)
Balance at June 30, 2012	$1.0	$1,027.2	$1,628.4	$(41.5)	$263.2	$(0.1)	$2,878.2
Balance at December 31, 2010	$1.0	$968.2	$1,380.6	$(60.2)	$110.4	$—	$2,400.0
Comprehensive income (loss)							
Net income	—	—	127.8	—	11.2	—	139.0
Other comprehensive income (loss), net of tax	—	—	—	18.4	0.7	—	19.1
Comprehensive income (loss)	—	—	127.8	18.4	11.9	—	158.1
Dividends declared on common stock	—	—	(73.5)	—	—	—	(73.5)
Issuance of common stock	—	7.5	—	—	—	—	7.5
Stock-based compensation	—	0.1	—	—	—	—	0.1
Contributions from noncontrolling interest partners	—	29.1	—	—	44.4	—	73.5
Distributions to noncontrolling interest partners	—	—	—	—	(6.1)	—	(6.1)
Deferred income taxes attributable to contributions from noncontrolling interest partners	—	(11.2)	—	—	—	—	(11.2)
Balance at June 30, 2011	$1.0	$993.7	$1,434.9	$(41.8)	$160.6	$—	$2,548.4

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

Organization

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. All significant intercompany transactions have been eliminated in consolidation.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. At June 30, 2012, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC, a Delaware single-member limited liability company. The Company consolidates Enogex Holdings in its Condensed Consolidated Financial Statements as OGE Energy has a controlling financial interest over the operations of Enogex Holdings. Also, Enogex LLC holds a 50 percent ownership interest in Atoka. The Company consolidates Atoka in its Condensed Consolidated Financial Statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka.

Basis of Presentation

The Condensed Consolidated Financial Statements included herein have been prepared by the Company, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.
In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at June 30, 2012 and December 31, 2011, the results of its operations for the three and six months ended June 30, 2012 and 2011 and the results of its cash flows for the six months ended June 30, 2012 and 2011, have been included and are of a normal recurring nature except as otherwise disclosed.

Due to seasonal fluctuations and other factors, the Company's operating results for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012 or for any future period. The Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the audited Consolidated Financial Statements and Notes thereto included in the Company's 2011 Form 10-K.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of OG&E's regulatory assets and liabilities at:

(In millions)	June 30, 2012	December 31, 2011
Regulatory Assets		
Current		
Oklahoma demand program rider under recovery (A)	$12.3	$8.1
Crossroads rider under recovery (A)	10.6	2.5
Fuel clause under recoveries	0.7	1.8
Other (A)	11.3	3.6
Total Current Regulatory Assets	$34.9	$16.0
Non-Current		
Benefit obligations regulatory asset	$345.1	$359.2
Income taxes recoverable from customers, net	54.7	54.0
Smart Grid	42.3	37.2
Deferred storm expenses	18.9	23.8
Unamortized loss on reacquired debt	13.6	14.2
Deferred pension expenses	6.8	9.1
Other	12.7	10.4
Total Non-Current Regulatory Assets	$494.1	$507.9
Regulatory Liabilities		
Current		
Fuel clause over recoveries	$65.4	$7.7
Smart Grid rider over recovery (B)	25.9	24.3
Other (B)	15.4	13.7
Total Current Regulatory Liabilities	$106.7	$45.7
Non-Current		
Accrued removal obligations, net	$213.6	$208.2
Pension tracker	28.9	22.5
Total Non-Current Regulatory Liabilities	$242.5	$230.7

(A) Included in Other Current Assets on the Condensed Consolidated Balance Sheets.
(B) Included in Other Current Liabilities on the Condensed Consolidated Balance Sheets.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If OG&E were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Property, Plant and Equipment

Enogex Cox City Plant Fire

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. In March 2012, Enogex reached a settlement agreement with its insurers in this matter. As a result of the settlement agreement, Enogex received additional reimbursements of $7.6 million during the six months ended June 30, 2012. Enogex recognized a gain of $7.5 million on insurance proceeds during the six months ended June 30, 2012.

Asset Retirement Obligation

The following table summarizes changes to OG&E's asset retirement obligations related to its wind farms due to a change in the assumption related to the timing of removal used in the valuation of the asset retirement obligations.

(In millions)	
Balance at January 1, 2012	$24.8
Accretion expense	0.9
Revisions in estimated cash flows	26.7
Balance at June 30, 2012	$52.4

Accumulated Other Comprehensive Income (Loss)

The following table summarizes the components of accumulated other comprehensive loss at June 30, 2012 and December 31, 2011 attributable to OGE Energy. At both June 30, 2012 and December 31, 2011, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

(In millions)	June 30, 2012	December 31, 2011
Pension Plan and Restoration of Retirement Income Plan:		
Net loss	$(40.6)	$(42.1)
Prior service cost	—	(0.1)
Postretirement plans:		
Net loss	(14.4)	(15.4)
Prior service cost	8.1	9.0
Net transition obligation	(0.1)	(0.1)
Deferred commodity contracts hedging gains (losses)	(0.3)	3.3
Deferred interest rate swaps hedging losses	(0.6)	(0.7)
Total accumulated other comprehensive loss	(47.9)	(46.1)
Less: Accumulated other comprehensive loss attributable to noncontrolling interests	(6.4)	(5.5)
Accumulated other comprehensive loss, net of tax	$(41.5)	$(40.6)

2. Noncontrolling Interests

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings makes quarterly distributions to its partners. The following table summarizes the quarterly distributions during the six months ended June 30, 2012.

(In millions)	OGE Holdings Portion	ArcLight group's Portion	Total Distribution
First quarter 2012	$24.4	$5.6	$30.0
Second quarter 2012	10.1	2.4	12.5
Total	$34.5	$8.0	$42.5

During the six months ended June 30, 2012, Atoka's noncontrolling interest partner made contributions of $1.0 million to Atoka. Enogex LLC made no distributions during the six months ended June 30, 2012 to its Atoka partner, as there is no minimum distribution requirement related to Atoka.

3. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Consolidated Balance Sheets. The Company has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Company's assets and liabilities that are measured at fair value on a recurring basis at June 30, 2012 and December 31, 2011 as well as reconcile the Company's commodity contracts fair value to PRM Assets and Liabilities on the Company's Condensed Consolidated Balance Sheets at June 30, 2012 and

December 31, 2011. The Company held no Level 3 investments at June 30, 2012 or December 31, 2011.

June 30, 2012

(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets (B)	Liabilities (C)
Quoted market prices in active market for identical assets (Level 1)	$16.3	$18.0	$—	$—
Significant other observable inputs (Level 2)	1.8	0.9	6.8	—
Total fair value	18.1	18.9	6.8	—
Netting adjustments	(17.1)	(18.5)	—	—
Total	$1.0	$0.4	$6.8	$—

December 31, 2011

(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (C)
Quoted market prices in active market for identical assets (Level 1)	$57.1	$52.3	$—	$—
Significant other observable inputs (Level 2)	4.2	1.2	1.8	7.8
Total fair value	61.3	53.5	1.8	7.8
Netting adjustments	(57.5)	(53.0)	—	—
Total	$3.8	$0.5	$1.8	$7.8

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $3.3 million at June 30, 2012 with no comparable item at December 31, 2011, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $1.5 million and $2.0 million at June 30, 2012 and December 31, 2011, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the Company's assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the six months ended June 30, 2011. There were no Level 3 investments held at June 30, 2012 or December 31, 2011.

(In millions)	Commodity Contracts Assets
Balance at January 1	$13.3
Total gains or losses	
Included in other comprehensive income	(4.8)
Settlements	(3.3)
Balance at March 31	5.2
Total gains or losses	
Included in other comprehensive income	(1.0)
Settlements	(1.7)
Balance at June 30	$2.5

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The following table summarizes the fair value and carrying amount of the Company's financial instruments, including derivative contracts related to the Company's PRM activities, at June 30, 2012 and December 31, 2011.

	June 30, 2012		December 31, 2011	
(In millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
PRM Assets				
Energy Derivative Contracts	$1.0	$1.0	$3.8	$3.8
PRM Liabilities				
Energy Derivative Contracts	$0.4	$0.4	$0.5	$0.5
Long-Term Debt				
OG&E Senior Notes	$1,904.0	$2,358.9	$1,903.8	$2,383.8
OGE Energy Senior Notes	99.8	106.3	99.8	108.5
OG&E Industrial Authority Bonds	135.4	135.4	135.4	135.4
Enogex LLC Senior Notes	448.3	497.8	448.1	497.9
Enogex LLC Revolving Credit Agreement	150.0	150.0	150.0	150.0

The carrying value of the financial instruments included in the Condensed Consolidated Balance Sheets approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

4. Derivative Instruments and Hedging Activities

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. The Company is also exposed to credit risk in its business operations.

Commodity Price Risk

The Company primarily uses forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures. Commodity derivative instruments used by the Company are as follows:

- NGLs put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing operations and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets;
- natural gas futures and swaps and natural gas commodity purchases and sales are used to manage OER's natural gas exposure associated with its storage and transportation contracts; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage OER's marketing and trading activities.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings are recognized in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations, (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business, (iii) electric power contracts by OG&E and (iv) fuel procurement by OG&E.

The Company recognizes its non-exchange traded derivative instruments as PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Consolidated Balance Sheets.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

The Company is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Enogex's cash flow hedges at June 30, 2012 mature by the end of the first quarter of 2013.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Company includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At June 30, 2012 and December 31, 2011, the Company had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated as Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in OER's asset management, marketing and trading activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

At June 30, 2012, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	2012 Gross Notional Volume (A)
Enogex marketing hedges	
Natural gas sales	2.6

(A) Natural gas in MMBtu's.

At June 30, 2012, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Gross Notional Volume (A)	
	Purchases	Sales
Natural gas (B)		
Physical (C)(D)	7.7	31.0
Fixed Swaps/Futures	57.9	59.7
Options	13.3	12.3
Basis Swaps	15.1	21.6

(A) Natural gas in MMBtu's.

(B) 96.9 percent of the natural gas contracts have durations of one year or less, 1.8 percent have durations of more than one year and less than two years and 1.3 percent have durations of more than two years.

(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.

(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Company's Condensed Consolidated Balance Sheet at June 30, 2012 are as follows:

Instrument	Balance Sheet Location	Fair Value	
		Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	$—	$0.5
Total		$—	$0.5
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$0.2	$0.1
	Other Current Assets	16.5	17.4
Physical Purchases/Sales	Current PRM	0.8	0.4
	Non-Current PRM	0.1	—
Financial Options	Other Current Assets	0.5	0.5
Total		$18.1	$18.4
Total Gross Derivatives (A)		$18.1	$18.9

(A) See Note 3 for a reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at June 30, 2012.

The fair value of the derivative instruments that are presented in the Company's Condensed Consolidated Balance Sheet at December 31, 2011 are as follows:

Instrument	Balance Sheet Location	Fair Value	
		Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	$5.2	$0.3
Total		$5.2	$0.3
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$0.4	$—
	Other Current Assets	49.9	49.9
Physical Purchases/Sales	Current PRM	3.1	0.4
	Non-Current PRM	0.3	0.1
Financial Options	Other Current Assets	2.4	2.8
Total		$56.1	$53.2
Total Gross Derivatives (A)		$61.3	$53.5

(A) See Note 3 for a reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at December 31, 2011.

Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended June 30, 2012.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income (A)	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
Natural Gas Financial Futures/Swaps	$(0.5)	$—	$—
Total	$(0.5)	$—	$—

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at June 30, 2012 that is expected to be reclassified into income within the next 12 months is a loss of $0.5 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(3.7)
Natural Gas Financial Futures/Swaps	0.6
Total	$(3.1)

The following tables present the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended June 30, 2011.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
NGLs Financial Options	$(2.4)	$(3.3)	$—
Natural Gas Financial Futures/Swaps	0.1	(7.4)	—
Total	$(2.3)	$(10.7)	$—

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(2.9)
Natural Gas Financial Futures/Swaps	(0.2)
Total	$(3.1)

The following tables present the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the six months ended June 30, 2012.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income (A)	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
Natural Gas Financial Futures/Swaps	$(0.2)	$5.2	$—
Total	$(0.2)	$5.2	$—

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at June 30, 2012 that is expected to be reclassified into income within the next 12 months is a loss of $0.5 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(6.1)
Natural Gas Financial Futures/Swaps	1.0
Total	$(5.1)

The following tables present the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the six months ended June 30, 2011.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
NGLs Financial Options	$(9.2)	$(5.8)	$—
Natural Gas Financial Futures/Swaps	(0.1)	(14.7)	—

Total	$(9.3	)$(20.5	)$—

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Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(5.0)
Natural Gas Financial Futures/Swaps	(0.4)
Total	$(5.4)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income into income (effective portion) and amounts recognized in income (ineffective portion) for the three and six months ended June 30, 2012 and 2011, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the three and six months ended June 30, 2012 and 2011, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at June 30, 2012, the Company would have been required to post $0.1 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at June 30, 2012. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

5. Stock-Based Compensation

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit during the three and six months ended June 30, 2012 and 2011 related to the Company's performance units and restricted stock.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2012	2011	2012	2011
Performance units				
Total shareholder return	$2.0	$1.9	$3.8	$3.7
Earnings per share	0.6	0.8	1.3	3.0
Total performance units	2.6	2.7	5.1	6.7
Restricted stock	0.2	0.2	0.4	0.5
Total compensation expense	$2.8	$2.9	$5.5	$7.2
Income tax benefit	$1.1	$1.1	$2.2	$2.8

During the three and six months ended June 30, 2012, there were 4,113 shares and 392,700 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. In November 2011, the Company purchased 120,000 shares of its common stock on the open market. During the three months ended March 31, 2012, 114,949 of these shares were used to payout Enogex's portion of earned performance units and during the three months ended June 30, 2012, 2,419 of these shares (net of forfeitures) were used to satisfy restricted stock grants. During the three and six months ended June 30, 2012, there were 2,587 and 2,932 shares of restricted stock, respectively, returned to the Company to satisfy tax liabilities. The Company received $0.1 million during each of the three and six months ended June 30, 2012 related to exercised stock options. The Company did not realize an income tax benefit for the tax deductions from the exercised stock options during the three and six months ended June 30, 2012 due to the Company being in a tax net operating loss position in 2012.

The following table summarizes the activity of the Company's stock-based compensation during the three months ended June 30, 2012.

	Shares	Fair Value
Grants		
Restricted stock	358	$51.73

6. Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2007 or state and local tax examinations by tax authorities for years prior to 2002. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. OG&E continues to amortize its Federal investment tax credits on a ratable basis throughout the year. OG&E earns both Federal and Oklahoma state tax credits associated with the production from its wind farms. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate.

7. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 60,779 shares and 129,112 shares, respectively, of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan during the three and six months ended June 30, 2012 and received proceeds of $3.3 million and $6.9 million, respectively. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan to fund capital requirements or working capital needs. At June 30, 2012, there were 2,239,931 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

Earnings Per Share

Basic earnings per share is calculated by dividing net income attributable to OGE Energy by the weighted average number of the Company's common shares outstanding during the period. In the calculation of diluted earnings per share, weighted average shares outstanding are increased for additional shares that would be outstanding if potentially dilutive securities were converted to common stock. Potentially dilutive securities for the Company consist of performance units. Basic and diluted earnings per share for the Company were calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2012	2011	2012	2011
Net Income Attributable to OGE Energy	$93.9	$103.0	$131.0	$127.8
Average Common Shares Outstanding				
Basic average common shares outstanding	98.6	98.0	98.4	97.8
Effect of dilutive securities:				
Contingently issuable shares (performance units)	0.3	1.3	0.4	1.4
Diluted average common shares outstanding	98.9	99.3	98.8	99.2
Basic Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders	$0.95	$1.05	$1.33	$1.31
Diluted Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders	$0.95	$1.04	$1.33	$1.29
Anti-dilutive shares excluded from earnings per share calculation	—	—	—	—

8. Long-Term Debt

At June 30, 2012, the Company was in compliance with all of its debt agreements.

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds at various dates prior to the maturity. The bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES	DATE DUE	AMOUNT (In millions)
0.22% - 0.40%	Garfield Industrial Authority, January 1, 2025	$47.0
0.21% - 0.41%	Muskogee Industrial Authority, January 1, 2025	32.4
0.20% - 0.38%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)		$135.4

All of these bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the bond by delivering an irrevocable notice to the tender agent stating the principal amount of the bond, payment instructions for the purchase price and the business day the bond is to be purchased. The repayment option may only be exercised by the holder of a bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the bonds will attempt to remarket any bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such bonds, OG&E is obligated to repurchase such unremarketed bonds. As OG&E has both the intent and ability to refinance the bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the bonds are classified as long-term debt in the Company's Condensed Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

9. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $596.7 million and $277.1 million at June 30, 2012 and December 31, 2011, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at June 30, 2012.

Revolving Credit Agreements and Available Cash

Entity	Aggregate Commitment (In millions)	Amount Outstanding (A)	Weighted-Average Interest Rate		Maturity
OGE Energy (B)	$750.0	$596.7	0.46	% (E)	December 13, 2016
OG&E (C)	400.0	2.2	0.53	% (E)	December 13, 2016
Enogex LLC (D)	400.0	150.0	1.62	% (E)	December 13, 2016
	1,550.0	748.9	0.69	%	
Cash	1.7	N/A	N/A		N/A
Total	$1,551.7	$748.9	0.69	%	

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at June 30, 2012.

(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At June 30, 2012, there was $596.7 million in outstanding commercial paper borrowings.

(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At June 30, 2012, there was $2.2 million in letters of credit.

(D) This bank facility is available to provide revolving credit borrowings for Enogex LLC. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Condensed Consolidated Balance Sheets.

(E) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.

The Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit.

OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2011 and ending December 31, 2012.

10. Retirement Plans and Postretirement Benefit Plans

The details of net periodic benefit cost of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans included in the Condensed Consolidated Financial Statements are as follows:

Net Periodic Benefit Cost

	Pension Plan				Restoration of Retirement Income Plan			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2012 (B)	2011 (B)	2012 (C)	2011 (C)	2012 (B)	2011 (B)	2012 (C)	2011 (C)
Service cost	$4.5	$4.4	$9.0	$8.8	$0.2	$0.2	$0.5	$0.5
Interest cost	7.5	8.3	15.0	16.6	0.2	0.2	0.3	0.3
Expected return on plan assets	(11.5)	(11.3)	(23.0)	(22.7)	—	—	—	—
Amortization of net loss	6.0	4.8	11.9	9.6	0.1	0.1	0.2	0.2
Amortization of unrecognized prior service cost (A)	0.5	0.6	1.1	1.2	0.1	0.2	0.3	0.4
Net periodic benefit cost	$7.0	$6.8	$14.0	$13.5	$0.6	$0.7	$1.3	$1.4

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $7.6 million and $7.5 million of net periodic benefit cost recognized by the Company during the three months ended June 30, 2012 and 2011, respectively, OG&E recognized an increase in pension expense during each of the three months ended June 30, 2012 and 2011 of $2.8 million to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1).

(C) In addition to the $15.3 million and $14.9 million of net periodic benefit cost recognized by the Company during the six months ended June 30, 2012 and 2011, respectively, OG&E recognized an increase in pension expense during the six months ended June 30, 2012 and 2011 of $5.7 million and $5.3 million, respectively, to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1).

	Postretirement Benefit Plans			
	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2012 (B)	2011 (B)	2012 (C)	2011 (C)
Service cost	$1.1	$0.9	$2.1	$1.8
Interest cost	3.0	3.1	6.0	6.2
Expected return on plan assets	(0.7)	(1.3)	(1.5)	(2.6)
Amortization of transition obligation	0.7	0.7	1.4	1.4
Amortization of net loss	5.1	4.5	10.2	9.1
Amortization of unrecognized prior service cost (A)	(4.2)	(4.1)	(8.3)	(8.2)
Net periodic benefit cost	$5.0	$3.8	$9.9	$7.7

(A)

Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $5.0 million and $3.8 million of net periodic benefit cost recognized by the Company during the three months ended June 30, 2012 and 2011, respectively, OG&E recognized an increase in postretirement medical expense during the three months ended June 30, 2012 and 2011, of $0.4 million and $1.7 million, respectively, to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1).

(C) In addition to the $9.9 million and $7.7 million of net periodic benefit cost recognized by the Company during the six months ended June 30, 2012 and 2011, respectively, OG&E recognized an increase in postretirement medical expense during the six months ended June 30, 2012 and 2011, of $0.8 million and $1.7 million, respectively, to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1).

11. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. Other Operations primarily includes the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of the Company's business segments during the three and six months ended June 30, 2012 and 2011.

Three Months Ended June 30, 2012	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$528.0	$75.1	$266.4	$76.6	$—	$(91.1)	$855.0
Cost of goods sold	204.6	37.4	178.6	79.5	—	(90.8)	409.3
Gross margin on revenues	323.4	37.7	87.8	(2.9)	—	(0.3)	445.7
Other operation and maintenance	114.7	10.6	29.9	2.2	(4.4)	—	153.0
Depreciation and amortization	62.7	5.4	18.6	0.3	3.5	—	90.5
Impairment of assets	—	—	0.1	—	—	—	0.1
Taxes other than income	18.2	3.5	2.1	0.1	0.9	—	24.8
Operating income (loss)	$127.8	$18.2	$37.1	$(5.5)	$—	$(0.3)	$177.3
Total assets	$6,833.2	$2,051.8	$1,623.0	$47.5	$331.4	$(1,535.5)	$9,351.4

Three Months Ended June 30, 2011	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$568.7	$108.0	$289.1	$168.3	$—	$(156.0)	$978.1
Cost of goods sold	254.3	69.5	210.9	170.4	—	(155.0)	550.1
Gross margin on revenues	314.4	38.5	78.2	(2.1)	—	(1.0)	428.0
Other operation and maintenance	110.2	13.0	26.3	2.0	(4.2)	(0.7)	146.6
Depreciation and amortization	52.1	5.8	13.4	0.1	3.3	—	74.7
Taxes other than income	18.8	3.3	1.7	(0.1)	0.8	—	24.5
Operating income (loss)	$133.3	$16.4	$36.8	$(4.1)	$0.1	$(0.3)	$182.2
Total assets	$6,290.5	$1,474.8	$1,106.7	$80.2	$152.4	$(969.1)	$8,135.5

Six Months Ended June 30, 2012	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$954.7	$154.2	$570.9	$206.6	$—	$(190.7)	$1,695.7
Cost of goods sold	400.1	80.9	396.5	206.7	—	(189.6)	894.6
Gross margin on revenues	554.6	73.3	174.4	(0.1)	—	(1.1)	801.1
Other operation and maintenance	225.3	21.4	60.0	4.4	(9.7)	(0.8)	300.6
Depreciation and amortization	122.4	10.6	36.4	0.7	7.0	—	177.1

Impairment of assets	—	—	0.3	—	—	—	0.3
Gain on insurance proceeds	—	—	(7.5)	—	—	—	(7.5)
Taxes other than income	39.3	8.2	4.6	0.2	2.7	—	55.0
Operating income (loss)	$167.6	$33.1	$80.6	$(5.4)	$—	$(0.3)	$275.6
Total assets	$6,833.2	$2,051.8	$1,623.0	$47.5	$331.4	$(1,535.5)	$9,351.4

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Six Months Ended June 30, 2011	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$990.8	$208.2	$555.8	$366.4	$—	$(302.6)	$1,818.6
Cost of goods sold	473.7	133.5	407.2	369.7	—	(300.8)	1,083.3
Gross margin on revenues	517.1	74.7	148.6	(3.3)	—	(1.8)	735.3
Other operation and maintenance	216.0	22.1	53.1	4.1	(8.9)	(1.5)	284.9
Depreciation and amortization	103.9	11.2	26.9	0.1	6.6	—	148.7
Taxes other than income	37.9	7.6	3.6	0.1	2.4	—	51.6
Operating income (loss)	$159.3	$33.8	$65.0	$(7.6)	$(0.1)	$(0.3)	$250.1
Total assets	$6,290.5	$1,474.8	$1,106.7	$80.2	$152.4	$(969.1)	$8,135.5

12. Commitments and Contingencies

Except as set forth below and in Note 13, the circumstances set forth in Notes 16 and 17 to the Company's Consolidated Financial Statements included in the Company's 2011 Form 10-K appropriately represent, in all material respects, the current status of the Company's material commitments and contingent liabilities.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,391 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

OG&E Wind Farm Land Lease Agreements

OG&E has wind farm land operating leases for its Centennial, OU Spirit and Crossroads wind farms expiring at various dates. Although the leases are cancellable, OG&E is required to make annual lease payments as long as the wind turbines are located on the land. OG&E does not expect to terminate the leases until the wind turbines reach the end of their economic life. Future minimum payments for these operating leases are as follows:

(In millions)	2012	2013	2014	2015	2016	2017 and Beyond	Total
OG&E wind farm land leases	$2.0	$2.0	$2.1	$2.1	$2.1	$53.9	$64.2

Natural Gas Measurement Cases

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of OGE Energy were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-Federal lands. On

April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended class action petition, and the court granted the motion on July 28, 2003. In its amended petition, OG&E and Enogex Inc. were omitted from the case but two of OGE Energy's other subsidiary entities remained as defendants. The plaintiffs' amended petition seeks class certification and alleges that 60 defendants, including two of OGE Energy's subsidiary entities, have improperly measured the volume of natural gas. The amended petition asserts theories of civil conspiracy, aiding and abetting, accounting and unjust enrichment. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims. On February 7, 2012, Enogex LLC and OER filed an application in the Kansas Court of Appeals seeking appeal of the trial court's denial of their motions for summary judgment. On February 23, 2012, the Kansas Court of Appeals denied this application. On March 23, 2012, Enogex LLC and OER filed an application with the Kansas Supreme Court seeking appeal of the Kansas Court of Appeals' decision. On July 19, 2012, the plaintiffs filed a motion to dismiss Enogex LLC and OER from the action. At this time, based on currently available information, OGE Energy does not believe it is reasonably possible that it will incur a material loss related to these proceedings and, therefore, OGE Energy does not believe the outcome will have a material impact on its financial position, results of operations or cash flows.

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price II). On May 12, 2003, the plaintiffs (same as those in the amended petition in Price I above) filed a new class action petition in the District Court of Stevens County, Kansas naming the same defendants and asserting substantially identical legal and/or equitable theories as in the amended petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two of OGE Energy's other subsidiary entities were named in this case. The plaintiffs allege that the defendants mismeasured the British thermal unit content of natural gas obtained from or measured for the plaintiffs. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims. On February 7, 2012, Enogex LLC and OER filed an application in the Kansas Court of Appeals seeking appeal of the trial court's denial of their motions for summary judgment. On February 23, 2012, the Kansas Court of Appeals denied this application. On March 23, 2012, Enogex LLC and OER filed an application with the Kansas Supreme Court seeking appeal of the Kansas Court of Appeals' decision. On July 19, 2012, the plaintiffs filed a motion to dismiss Enogex LLC and OER from the action. At this time, based on currently available information, OGE Energy does not believe it is reasonably possible that it will incur a material loss related to these proceedings and, therefore, OGE Energy does not believe the outcome will have a material impact on its financial position, results of operations or cash flows.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. At the present time, based on currently available information, except as otherwise stated above, in Note

13 below, under "Environmental Laws and Regulations" in Item 2 of Part 1 and in Item 1 of Part II of this Form 10-Q, in Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I of the Company's 2011 Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

13. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 17 to the Company's Consolidated Financial Statements included in the Company's 2011 Form 10-K appropriately represent, in all material respects, the current status of the Company's regulatory matters.

Completed Regulatory Matters

OG&E Contract and Wind Energy Purchase Agreement Filing

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project calls for OG&E to contract with NextEra Energy to build a 60 megawatt wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra Energy will build, own and operate the wind farm and OG&E will purchase the electric output. The wind farm is expected to be in service by the end of 2012. On February 22, 2012, OG&E, the Attorney General and the Public Utility Division of the OCC signed a settlement agreement whereby the stipulating parties requested that the OCC issue an order approving the agreement for electric service with Oklahoma State University. On March 12, 2012, OG&E received an order from the OCC approving the settlement agreement. Pursuant to the terms of the power purchase agreement between OG&E and NextEra Energy, OG&E will purchase the electric output of the wind farm and use that power to provide service to Oklahoma State University and its other retail customers.

SPP Transmission/Substation Projects

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line originating at OG&E's existing Sooner 345 kilovolt substation and proceeding generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were $45 million.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kilovolt transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line extends from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. The transmission line was completed in April 2012. The total capital expenditures associated with this project were $157 million.

As discussed below, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider.

OG&E 2011 Oklahoma Rate Case Filing

As previously reported in the Company's 2011 Form 10-K, on July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E requested a return on equity of 11.0 percent based on a common equity percentage of 53.0 percent. In its application, OG&E requested recovery of increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On July 2, 2012, OG&E and other parties associated with its rate increase reached a settlement agreement in this matter. Key terms of the settlement agreement include: (i) an annual net increase of approximately $4.3 million in OG&E's rates to its Oklahoma retail customers; (ii) OG&E's Oklahoma retail authorized return on equity will be 10.2 percent; (iii) the rate of return to be used under various recovery riders previously approved by the OCC, including riders for OG&E's smart grid implementation and Crossroads wind farm will be based on OG&E's actual debt and equity ratios as reflected in OG&E's application and a 10.2 percent return on equity; (iv) depreciation rates proposed by OG&E will be implemented in the same month new customer rates go into effect; (v) the pension and postretirement medical cost tracker will remain in effect; (vi) a procedure was established to expedite the recovery of the cost of specified high-voltage transmission projects; and (vii) extension of funding for OG&E's system hardening program. On July 9, 2012, the OCC issued an order approving the settlement agreement in this matter. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries from lower than forecasted fuel costs. OG&E implemented the new rates effective in early August.

Pending Regulatory Matters

OG&E Fuel Adjustment Clause Review for Calendar Year 2010

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2010, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On April 6, 2012 witnesses for the OCC Staff, the Oklahoma Attorney General and the Oklahoma Industrial Energy Consumers association filed responsive testimony. The witness for the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately $44 million of costs previously recovered through OG&E’s fuel adjustment clause. These recommendations were based on allegations that OG&E’s lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. The witnesses for the OCC Staff and the Oklahoma Attorney General recommended that OG&E should provide additional information to allow them to reach a conclusion on their prudence review. On May 8, 2012, OG&E filed rebuttal testimony supporting the appropriateness of OG&E's use of coal-fired generation during 2010, OG&E's practice regarding purchasing power and the appropriateness of OG&E's management actions related to the Sooner 2 outage. A hearing on the merits was conducted on July 17 and 18, 2012. The witness for the Oklahoma Attorney General offered no further testimony. The witness for the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund $3 million to customers because of the Sooner 2 outage. The administrative law judge took the matter under advisement. OG&E believes that the recommendations for the disallowances made by the witnesses for the Oklahoma Industrial Energy Consumers and the OCC Staff are without merit.

SPP Transmission/Substation Projects

On January 31, 2012, the SPP approved the Integrated Transmission Plan Near Term and Integrated Transmission Plan 10-year projects. These plans include two projects to be built by OG&E and include: (i) construction of 47 miles of transmission line from OG&E's Gracemont substation in a northwestern direction to a companion transmission line to be built by American Electric Power to its Elk City substation at an estimated cost of $75 million for OG&E, which is expected to be in service by early 2018 and (ii) construction of 126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southeastern direction to OG&E's Cimarron substation and construction of a new substation on this transmission line, the Mathewson substation, at an estimated cost of $210 million for OG&E, which is expected to be in service by early 2021. On April 9, 2012, OG&E received a notice to construct these projects from the SPP. On June 26, 2012, OG&E responded to the SPP that OG&E will construct the projects discussed above and is moving forward with more detailed cost estimates that must be reviewed and approved by the SPP.

Market-Based Rate Authority

On June 29, 2012, OG&E filed its triennial market power update with the FERC to retain its market-based rate authorization in the SPP's energy imbalance service market but to surrender its market-based rate authorization for any market-based rate sales outside the SPP's energy imbalance service market. A FERC order is pending.

Enogex FERC Section 311 2011 Rate Case

On January 28, 2011, Enogex submitted a new rate filing to the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement in this matter cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. On January 10, 2012, Enogex filed a settlement agreement in this matter with the FERC. On May 4, 2012, the FERC issued an order approving the settlement agreement in this matter, subject to the submission of a compliance filing to place the settlement rates into effect as of March 1, 2011, which compliance filing was subsequently filed on May 31, 2012. The FERC also requested that Enogex file a revised statement of operating conditions, which was subsequently filed on May 31, 2012. As part of the settlement agreement in this matter, Enogex made refunds of $0.2 million to affected customers on June 15, 2012 and submitted a report to the FERC on July 6, 2012 showing the refund payment calculation. A FERC order is pending.

Enogex 2011 Fuel Filing

On February 28, 2011, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West for the 2011 fuel year (April 1, 2011 through March 31, 2012). Along with the revised fuel percentages, Enogex also requested authority to revise its statement of operating conditions to permanently change the annual filing date to February 28. The deadline for interventions and protests to Enogex's filing was March 15, 2011, and no protests were filed. On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2011 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement discussed above. A FERC order is pending.

Enogex 2012 Fuel Filing

On February 24, 2012, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the 2012 fuel year (April 1, 2012 through March 31, 2013). The deadline for interventions and protests on the filing was March 27, 2012. Two parties intervened in the proceeding. On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2012 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement discussed above. A FERC order is pending.

14. Subsequent Event

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area for an aggregate purchase price of approximately $70 million which is expected to be paid in cash. The purchase price is subject to certain adjustments, including Enogex's obligation to reimburse the sellers for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending upon the consummation of the transactions contemplated by these agreements. The consummation of the transactions contemplated by the agreements is subject to customary conditions to closing, including the expiration or early termination of the waiting period under the Hart-Scott-Rodino Act.
In connection with these agreements, Enogex will enter into a gas gathering and processing agreement with Chesapeake pursuant to which Enogex will provide fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake. Including the purchase price of the assets discussed above, Enogex projects additional capital expenditures for the construction of gathering and compression assets associated with these agreements to be approximately $325 million through the remainder of 2012 and 2013. Effectiveness of the gas gathering and processing agreement is contingent on the closing of the agreements discussed above.

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

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. At June 30, 2012, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC.

During the third quarter of 2012, the operations and activities of OER will be fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions.

Overview

Company Strategy

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services in a safe, reliable and efficient manner. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and unregulated natural gas midstream business while providing competitive energy products and services to customers primarily in the south central United States as well as seeking growth opportunities in both businesses. Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders. The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

Summary of Operating Results
Three Months Ended June 30, 2012 as Compared to Three Months Ended June 30, 2011

Net income attributable to OGE Energy was $93.9 million, or $0.95 per diluted share, during the three months ended June 30, 2012 as compared to $103.0 million, or $1.04 per diluted share, during the same period in 2011. The decrease in net income attributable to OGE Energy of $9.1 million, or 8.8 percent, during the three months ended June 30, 2012 as compared to the same period in 2011 was primarily due to:

- a decrease in net income at OG&E of $5.2 million, or 6.6 percent, or $0.05 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense and higher depreciation and amortization expense partially offset by a higher gross margin and lower income tax expense. The higher gross margin was primarily due to increased recovery of investments and increased transmission revenue partially offset by milder weather in OG&E's service territory; and
- a decrease in net income at Enogex of $4.1 million, or 16.4 percent, or $0.04 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense and lower other income primarily due to the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in 2011 partially offset by a higher gross margin and lower income tax expense. The higher gross margin is primarily related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from certain gas gathering assets acquired in November 2011 and (ii) increased inlet volumes partially offset by lower average natural gas prices and lower average NGLs prices.

Six Months Ended June 30, 2012 as Compared to Six Months Ended June 30, 2011

Net income attributable to OGE Energy was $131.0 million, or $1.33 per diluted share, during the six months ended June 30, 2012 as compared to $127.8 million, or $1.29 per diluted share, during the same period in 2011. The increase in net income attributable to OGE Energy of $3.2 million, or 2.5 percent, during the six months ended June 30, 2012 as compared to the same period in 2011 was primarily due to:

- an increase in net income at OG&E of $0.5 million, or 0.6 percent, or $0.01 per diluted share of the Company's common stock, primarily due to a higher gross margin and lower income tax expense. The higher gross margin was primarily due to increased recovery of investments and increased transmission revenue partially offset by milder weather in OG&E's service territory. The gross margin increases were partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and higher interest expense; and
- an increase in net income at Enogex of $2.1 million, or 4.8 percent, or $0.02 per diluted share of the Company's common stock, primarily due to a higher gross margin related to (i) increased gathering rates and volumes

associated with ongoing expansion projects and increased volumes from certain gas gathering assets acquired in November 2011 and (ii) increased inlet volumes partially offset by lower average natural gas prices and lower average NGLs prices. Also contributing to the increase was a gain on insurance proceeds. These increases were partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and lower other income primarily due to the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in 2011.

Recent Developments and Regulatory Matters

OG&E 2011 Oklahoma Rate Case Filing

As previously reported in the Company's 2011 Form 10-K, on July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E requested a return on equity of 11.0 percent based on a common equity percentage of 53.0 percent. In its application, OG&E requested recovery of increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On July 2, 2012, OG&E and other parties associated with its rate increase reached a settlement agreement in this matter. Key terms of the settlement agreement include: (i) an annual net increase of approximately $4.3 million in OG&E's rates to its Oklahoma retail customers; (ii) OG&E's Oklahoma retail authorized return on equity will be 10.2 percent; (iii) the rate of return to be used under various recovery riders previously approved by the OCC, including riders for OG&E's smart grid implementation and Crossroads wind farm will be based on OG&E's actual debt and equity ratios as reflected in OG&E's application and a 10.2 percent return on equity; (iv) depreciation rates proposed by OG&E will be implemented in the same month new customer rates go into effect; (v) the pension and postretirement medical cost tracker will remain in effect; (vi) a procedure was established to expedite the recovery of the cost of specified high-voltage transmission projects; and (vii) extension of funding for OG&E's system hardening program. On July 9, 2012, the OCC issued an order approving the settlement agreement in this matter. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries from lower than forecasted fuel costs. OG&E implemented the new rates effective in early August.

OG&E Fuel Adjustment Clause Review for Calendar Year 2010

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2010, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On April 6, 2012 witnesses for the OCC Staff, the Oklahoma Attorney General and the Oklahoma Industrial Energy Consumers association filed responsive testimony. The witness for the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately $44 million of costs previously recovered through OG&E’s fuel adjustment clause. These recommendations were based on allegations that OG&E’s lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. The witnesses for the OCC Staff and the Oklahoma Attorney General recommended that OG&E should provide additional information to allow them to reach a conclusion on their prudence review. On May 8, 2012, OG&E filed rebuttal testimony supporting the appropriateness of OG&E's use of coal-fired generation during 2010, OG&E's practice regarding purchasing power and the appropriateness of OG&E's management actions related to the Sooner 2 outage. A hearing on the merits was conducted on July 17 and 18, 2012. The witness for the Oklahoma Attorney General offered no further testimony. The witness for the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E

refund $3 million to customers because of the Sooner 2 outage. The administrative law judge took the matter under advisement. OG&E believes that the recommendations for the disallowances made by the witnesses for the Oklahoma Industrial Energy Consumers and the OCC Staff are without merit.

Enogex Western Oklahoma / Texas Panhandle Gathering and Processing System Expansions

Enogex expects to expand its cryogenic processing plant currently under construction in Wheeler County, Texas from a processing capacity of 120 MMcf/d to 200 MMcf/d with the installation of additional residue compression facilities. The initial 120 MMcf/d of processing capacity is expected to be in service in August 2012 and the remaining 80 MMcf/d is expected to be in service during the third quarter of 2012. The new plant will be supported by the installation of 9,400 horsepower of field compression, as well as 6,000 horsepower of inlet compression to facilitate additional flexibility in the operation of the Enogex "super-header" gathering system. The total capital expenditures associated with this project are expected to be $160 million.

In support of significant long-term acreage dedications from its customers in the area, Enogex continues to expand its gathering infrastructure in four counties of western Oklahoma. These expansions include the installation of 39,700 horsepower of low pressure compression and 235 miles of gathering pipe across the area. The construction of this infrastructure is expected to be completed during the third quarter of 2012. The total capital expenditures associated with these expansions projects are expected to be $185 million.

Enogex is constructing a 200 MMcf/d cryogenic processing plant in Custer County, Oklahoma. The new plant will be supported by 6,000 horsepower of inlet compression and 25 miles of transmission pipeline. This plant is expected to be in service by the end of 2013. The total capital expenditures associated with this project are expected to be $150 million.

Gas Gathering Acquisitions

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area for an aggregate purchase price of approximately $70 million which is expected to be paid in cash. The purchase price is subject to certain adjustments, including Enogex's obligation to reimburse the sellers for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending upon the consummation of the transactions contemplated by these agreements. The consummation of the transactions contemplated by the agreements is subject to customary conditions to closing, including the expiration or early termination of the waiting period under the Hart-Scott-Rodino Act.
In connection with these agreements, Enogex will enter into a gas gathering and processing agreement with Chesapeake pursuant to which Enogex will provide fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake. Including the purchase price of the assets discussed above, Enogex projects additional capital expenditures for the construction of gathering and compression assets associated with these agreements to be approximately $325 million through the remainder of 2012 and 2013. Effectiveness of the gas gathering and processing agreement is contingent on the closing of the agreements discussed above.

2012 Outlook

The Company's 2012 earnings guidance is between approximately $337 million and $357 million of net income, or $3.40 to $3.60 per average diluted share. Certain key factors and assumptions previously disclosed have changed and are listed below. All other factors and assumptions are unchanged from those included in the earnings guidance in the Company's 2011 Form 10-K and the Form 10-Q for the quarter ended March 31, 2012.

Key assumptions for 2012 include:

OG&E

The Company projects OG&E to earn approximately $258 million to $268 million or $2.60 to $2.70 per average diluted share in 2012 and is based on the following assumptions:

- Normal weather patterns are experienced for the remainder of the year;
- New Oklahoma retail rates in effect the first billing cycle of August 2012, which is projected to increase gross margin by approximately $3 million; and
-

The implementation of the transmission systems additions rider in October 2012, which is projected to increase gross margin by approximately $1 million.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

For additional information regarding the 2011 Oklahoma Rate Case Filing, see Note 13 of Notes to Condensed Consolidated Financial Statements.

Enogex

The Company's 2012 earnings projection for Enogex is unchanged and is between approximately $80 million to $95 million, or $0.80 to $0.95 per average diluted share, net of noncontrolling interest and is based on the following assumptions:

- Key factors affecting the gathering and processing gross margin forecast are:
- Assumed increase of 10 to 12 percent up from the previous forecast of six to10 percent in gathered volumes over 2011;
- Assumed increase of approximately 20 to 25 percent in processable volumes up from the previous forecast of 15 percent in processable* volumes over 2011;
- At the midpoint of Enogex's gathering and processing assumption Enogex has assumed:
- Processing contract mix of 40 percent fixed-fee, 24 percent percent-of-liquids, 16 percent percent-of-proceeds and 20 percent keep-whole;
- Weighted average natural gas price of $2.56 per MMBtu in 2012;
- Realized weighted average NGLs price of $1.04 per gallon in 2012 with rejection of ethane for the remainder of 2012 for plants with volumes dedicated to Conway, Kansas; and
- Average price per gallon of condensate of $1.96 in 2012;
- Up to $250 million of debt financing in the third quarter of 2012 with net interest expense remaining unchanged at $31 million to $33 million for 2012; and
- ArcLight group is projected to make an equity contribution of up to $60 million in the fourth quarter of 2012 and would subsequently own approximately 20 percent of Enogex Holdings by the end of 2012.

2013 Volume Projections for Enogex

- Assumed increase of 10 to 15 percent in gathered volumes over 2012; and
- Assumed increase of approximately 15 percent in processable* volumes over 2012.

* Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet volumes.

EBITDA is a supplemental non-GAAP financial measure used by external users of the Company's financial statements such as investors, commercial banks and others; therefore, the Company has included the table below which provides a reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings at the midpoint of Enogex Holdings' earnings assumptions for 2012, which does not include the effect of income taxes whereas OGE Energy's portion of Enogex Holdings' net income included in OGE Energy's earnings guidance does reflect the effect of income taxes. Enogex Holding's net income shown in the EBITDA table does not include the effect of income taxes because Enogex Holdings is a partnership and is not subject to income taxes. Each partner is responsible for paying their own income taxes. For a discussion of the reasons for the use of EBITDA, as well as its limitations as an analytical tool, see "Non-GAAP Financial Measure" below.

Reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings

(In millions)	Twelve Months Ended December 31, 2012 (A)(B)
Net income attributable to Enogex Holdings	$176
Add:	
Interest expense, net	32
Depreciation and amortization expense (C)	100
EBITDA	$308
OGE Energy's portion	$250

(A) Based on midpoint of Enogex Holdings' earnings guidance for 2012.
(B) As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.
(C) Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera Energy Partners III, LLC in November 2011, which is included in gross margin for financial reporting purposes.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the three and six months ended June 30, 2012 as compared to the same period in 2011 and the Company's consolidated financial position at June 30, 2012. Due to seasonal fluctuations and other factors, the operating results for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012 or for any future period. The following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions except per share data)	2012	2011	2012	2011
Operating income	$177.3	$182.2	$275.6	$250.1
Net income attributable to OGE Energy	$93.9	$103.0	$131.0	$127.8
Basic average common shares outstanding	98.6	98.0	98.4	97.8
Diluted average common shares outstanding	98.9	99.3	98.8	99.2
Basic earnings per average common share attributable to OGE Energy common shareholders	$0.95	$1.05	$1.33	$1.31
Diluted earnings per average common share attributable to OGE Energy common shareholders	$0.95	$1.04	$1.33	$1.29
Dividends declared per common share	$0.3925	$0.3750	$0.7850	$0.7500

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Condensed Consolidated Statements of Income, as operating income indicates the ongoing profitability of the Company excluding the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2012	2011	2012	2011
OG&E (Electric Utility)	$127.8	$133.3	$167.6	$159.3
Enogex (Natural Gas Midstream Operations)				
Transportation and storage	18.2	16.4	33.1	33.8
Gathering and processing	37.1	36.8	80.6	65.0
Marketing	(5.5)	(4.1)	(5.4)	(7.6)
Other Operations (A)	(0.3)	(0.2)	(0.3)	(0.4)
Consolidated operating income	$177.3	$182.2	$275.6	$250.1

(A) Other Operations primarily includes the operations of the holding company and consolidating eliminations.

The following operating income analysis by business segment includes intercompany transactions that are eliminated in the Condensed Consolidated Financial Statements.

OG&E (Electric Utility)

	Three Months Ended June 30,		Six Months Ended June 30,	
(Dollars in millions)	2012	2011	2012	2011
Operating revenues	$528.0	$568.7	$954.7	$990.8
Cost of goods sold	204.6	254.3	400.1	473.7
Gross margin on revenues	323.4	314.4	554.6	517.1
Other operation and maintenance	114.7	110.2	225.3	216.0
Depreciation and amortization	62.7	52.1	122.4	103.9
Taxes other than income	18.2	18.8	39.3	37.9
Operating income	127.8	133.3	167.6	159.3
Interest income	0.1	0.1	0.1	0.2
Allowance for equity funds used during construction	1.7	5.8	3.6	10.2
Other income	0.7	1.3	5.9	6.3
Other expense	0.6	0.9	1.3	1.5
Interest expense	31.1	27.3	62.0	53.4
Income tax expense	25.2	33.7	28.4	36.1
Net income	$73.4	$78.6	$85.5	$85.0
Operating revenues by classification				
Residential	$215.8	$234.4	$385.4	$411.2
Commercial	134.0	141.9	233.9	240.1
Industrial	51.1	55.9	95.3	100.0
Oilfield	40.7	42.7	77.3	77.6
Public authorities and street light	50.7	55.0	90.1	93.3
Sales for resale	13.1	14.9	25.9	28.1
System sales revenues	505.4	544.8	907.9	950.3
Off-system sales revenues	5.1	12.5	14.0	21.9
Other	17.5	11.4	32.8	18.6
Total operating revenues	$528.0	$568.7	$954.7	$990.8
Megawatt-hour sales by classification (In millions)				
Residential	2.2	2.3	4.1	4.5
Commercial	1.8	1.8	3.3	3.3
Industrial	1.0	1.0	2.0	1.9
Oilfield	0.9	0.8	1.7	1.6
Public authorities and street light	0.9	0.8	1.6	1.5
Sales for resale	0.3	0.4	0.6	0.7
System sales	7.1	7.1	13.3	13.5
Off-system sales	0.2	0.3	0.6	0.6
Total sales	7.3	7.4	13.9	14.1
Number of customers	793,998	786,125	793,998	786,125
Weighted-average cost of energy per kilowatt-hour - cents				
Natural gas	2.576	4.485	2.727	4.477
Coal	2.276	2.032	2.260	2.033
Total fuel	2.275	2.986	2.303	2.842
Total fuel and purchased power	2.669	3.255	2.701	3.156
Degree days (A)				
Heating - Actual	75	174	1,457	2,078
Heating - Normal	203	236	2,001	2,199
Cooling - Actual	793	885	854	926

Cooling - Normal	625	547	638	555

(A) Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

Three Months Ended June 30, 2012 as Compared to Three Months Ended June 30, 2011

OG&E's operating income decreased $5.5 million, or 4.1 percent, during the three months ended June 30, 2012 as compared to the same period in 2011 primarily due to higher other operation and maintenance expense and higher depreciation and amortization expense partially offset by a higher gross margin.

Gross Margin

Operating revenues were $528.0 million during the three months ended June 30, 2012 as compared to $568.7 million during the same period in 2011, a decrease of $40.7 million, or 7.2 percent. Cost of goods sold was $204.6 million during the three months ended June 30, 2012 as compared to $254.3 million during the same period in 2011, a decrease of $49.7 million, or 19.5 percent. Gross margin was $323.4 million during the three months ended June 30, 2012 as compared to $314.4 million during the same period in 2011, an increase of $9.0 million, or 2.9 percent. The gross margin increased primarily due to:

- an increased price variance due to revenues from the recovery of investments, including the Crossroads wind farm, Smart Grid and the OU Spirit wind farm and higher revenues from sales and customer mix, which increased the gross margin by $10.7 million;
- higher transmission revenue primarily due to the inclusion of construction work in progress in transmission rates for specific FERC approved projects that previously accrued allowance for funds used during construction, which increased the gross margin by $5.7 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $2.6 million;
- new customer growth in OG&E's service territory, which increased the gross margin by $1.8 million; and
- revenues from the Arkansas rate increase, which increased the gross margin by $1.4 million.

These increases in gross margin were partially offset by milder weather in OG&E's service territory, which decreased the gross margin by $13.8 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $145.8 million during the three months ended June 30, 2012 as compared to $205.3 million during the same period in 2011, a decrease of $59.5 million, or 29.0 percent, primarily due to lower natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. Purchased power costs were $55.7 million during the three months ended June 30, 2012 as compared to $47.1 million during the same period in 2011, an increase of $8.6 million, or 18.3 percent, primarily due to an increase in purchases in the energy imbalance service market and short-term power purchases partially offset by lower cogeneration purchases.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in base rates, are passed through to OG&E's customers through fuel adjustment clauses. See Note 13 of Notes to Condensed Consolidated Financial Statements for a discussion of OG&E's 2010 fuel adjustment clause review. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex.

Operating Expenses

Other operation and maintenance expense was $114.7 million during the three months ended June 30, 2012 as compared to $110.2 million during the same period in 2011, an increase of $4.5 million, or 4.1 percent. The increase in other operation and maintenance expense was primarily due to:

- an increase of $2.2 million in postretirement medical expense related to modifications to OG&E's pension tracker in 2011;

- an increase of $1.6 million in contract technical and construction services and an increase of $0.9 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at OG&E's power plants;
- an increase of $1.1 million in fees from the SPP and the North American Electric Reliability Corporation; and
- an increase of $1.1 million related to increased spending on vegetation management.

These increases in other operation and maintenance expense were partially offset by a decrease of $3.0 million allocated from the holding company primarily due to lower contract professional services.

Depreciation and amortization expense was $62.7 million during the three months ended June 30, 2012 as compared to $52.1 million during the same period in 2011, an increase of $10.6 million, or 20.3 percent, primarily due to additional assets being placed in service throughout 2011 and the six months ended June 30, 2012, including the Crossroads wind farm, which was fully in service in January 2012.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $1.7 million during the three months ended June 30, 2012 as compared to $5.8 million during the same period in 2011, a decrease of $4.1 million, or 70.7 percent, primarily due to higher levels of construction costs for the Crossroads wind farm in 2011.

Other Income. Other income was $0.7 million during the three months ended June 30, 2012 as compared to $1.3 million during the same period in 2011, a decrease of $0.6 million, or 46.2 percent. The decrease in other income was primarily due to a decrease of $2.6 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction partially offset by an increased margin of $1.9 million recognized in the guaranteed flat bill program during the three months ended June 30, 2012 due to higher than expected usage during the same period in 2011 as a result of warmer weather.

Interest Expense. Interest expense was $31.1 million during the three months ended June 30, 2012 as compared to $27.3 million during the same period in 2011, an increase of $3.8 million, or 13.9 percent, primarily due to a $2.0 million increase in interest expense related to the issuance of long-term debt in May 2011 and a $2.0 million increase in interest expense related to lower allowance for borrowed funds used during construction primarily due to construction costs for the Crossroads wind farm in 2011.

Income Tax Expense. Income tax expense was $25.2 million during the three months ended June 30, 2012 as compared to $33.7 million during the same period in 2011, a decrease of $8.5 million, or 25.2 percent, primarily due to lower pre-tax income and an increase in the amount of Federal renewable energy credits recognized during the three months ended June 30, 2012 as compared to the same period in 2011.

Six Months Ended June 30, 2012 as Compared to Six Months Ended June 30, 2011

OG&E's operating income increased $8.3 million, or 5.2 percent, during the six months ended June 30, 2012 as compared to the same period in 2011 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense.

Gross Margin

Operating revenues were $954.7 million during the six months ended June 30, 2012 as compared to $990.8 million during the same period in 2011, a decrease of $36.1 million, or 3.6 percent. Cost of goods sold was $400.1 million during the six months ended June 30, 2012 as compared to $473.7 million during the same period in 2011, a decrease of $73.6 million, or 15.5 percent. Gross margin was $554.6 million during the six months ended June 30, 2012 as compared to $517.1 million during the same period in 2011, an increase of $37.5 million, or 7.3 percent. The gross margin increased primarily due to:

- an increased price variance, due to revenues from the recovery of investments, including the Crossroads wind farm, Smart Grid, the OU Spirit wind farm and the Windspeed transmission line and higher revenues from sales and customer mix, which increased the gross margin by $34.8 million;
- higher transmission revenue primarily due to the inclusion of construction work in progress in transmission rates for specific FERC approved projects that previously accrued allowance for funds used during construction, which increased the gross margin by $14.7 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $5.1 million;
- new customer growth in OG&E's service territory, which increased the gross margin by $3.7 million;

- revenues from the Arkansas rate increase, which increased the gross margin by $2.8 million; and
- higher revenues related to the renewal of the Arkansas Valley Electric Cooperative contract, which increased the gross margin by $1.3 million.

These increases in gross margin were partially offset by milder weather in OG&E's service territory, which decreased the gross margin by $25.3 million.

Fuel expense was $288.9 million during the six months ended June 30, 2012 as compared to $376.4 million during the same period in 2011, a decrease of $87.5 million, or 23.2 percent, primarily due to lower natural gas prices.
Purchased power

costs were $104.7 million during the six months ended June 30, 2012 as compared to $93.5 million during the same period in 2011, an increase of $11.2 million, or 12.0 percent, primarily due to an increase in purchases in the energy imbalance service market and short-term power purchases partially offset by lower cogeneration purchases.

Operating Expenses

Other operation and maintenance expense was $225.3 million during the six months ended June 30, 2012 as compared to $216.0 million during the same period in 2011, an increase of $9.3 million, or 4.3 percent. The increase in other operation and maintenance expense was primarily due to:

- an increase of $3.1 million in salaries and wages expense primarily due to salary increases in 2012, an increase in accrued vacation expense due to adopting a new vacation policy effective January 1, 2012 and an increase in incentive compensation expense partially offset by a decrease in overtime expense;
- an increase of $2.6 million in employee benefits primarily due to an increase in postretirement medical expense related to modifications to OG&E's pension tracker in 2011 and an increase in retirement savings expense;
- an increase of $2.4 million in contract technical and construction services and an increase of $0.7 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at OG&E's power plants;
- an increase of $2.3 million related to increased spending on vegetation management;
- an increase of $1.7 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- an increase of $1.5 million in fees from the SPP and the North American Electric Reliability Corporation; and
- an increase of $1.1 million in software expense primarily related to Smart Grid, which expenses are being recovered through a rider.

These increases in other operation and maintenance expense were partially offset by:

- a decrease of $3.5 million due to an increase in capitalized labor in 2012 as compared to 2011;
- a decrease of $1.4 million in uncollectible expense; and
- a decrease of $1.1 million allocated from the holding company primarily due to a decrease in contract professional services.

Depreciation and amortization expense was $122.4 million during the six months ended June 30, 2012 as compared to $103.9 million during the same period in 2011, an increase of $18.5 million, or 17.8 percent, primarily due to additional assets being placed in service throughout 2011 and the six months ended June 30, 2012, including the Crossroads wind farm, which was fully in service in January 2012.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $3.6 million during the six months ended June 30, 2012 as compared to $10.2 million during the same period in 2011, a decrease of $6.6 million, or 64.7 percent, primarily due to higher levels of construction costs for the Crossroads wind farm in 2011.

Other Income. Other income was $5.9 million during the six months ended June 30, 2012 as compared to $6.3 million during the same period in 2011, a decrease of $0.4 million, or 6.3 percent. The decrease in other income was primarily due to a decrease of $4.2 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction partially offset by an increase of $3.4 million due to an increased margin recognized in the guaranteed flat bill program during the six months ended June 30, 2012 due to higher than expected usage during the same period in 2011 as a result of warmer weather.

Interest Expense. Interest expense was $62.0 million during the six months ended June 30, 2012 as compared to $53.4 million during the same period in 2011, an increase of $8.6 million, or 16.1 percent, primarily due to a $5.2 million increase in interest expense related to the issuance of long-term debt in May 2011 and a $3.2 million increase in interest expense related to lower allowance for borrowed funds used during construction primarily due to construction costs for the Crossroads wind farm in 2011.

Income Tax Expense. Income tax expense was $28.4 million during the six months ended June 30, 2012 as compared to $36.1 million during the same period in 2011, a decrease of $7.7 million, or 21.3 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income during the six months ended June 30, 2012 as compared to the same period in 2011; and
- an increase in the amount of Federal renewable energy credits recognized during the six months ended June 30, 2012 as compared to the same period in 2011.

These decreases in income tax expense were partially offset by a reduction in Oklahoma investment tax credits generated during the six months ended June 30, 2012 as compared to the same period in 2011.

Enogex (Natural Gas Midstream Operations)

Three Months Ended June 30, 2012 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$75.1	$266.4	$76.6	$(74.1)	$344.0
Cost of goods sold	37.4	178.6	79.5	(72.9)	222.6
Gross margin on revenues	37.7	87.8	(2.9)	(1.2)	121.4
Other operation and maintenance	10.6	29.9	2.2	0.1	42.8
Depreciation and amortization	5.4	18.6	0.3	—	24.3
Impairment of assets	—	0.1	—	—	0.1
Gain on insurance proceeds	—	—	—	—	—
Taxes other than income	3.5	2.1	0.1	—	5.7
Operating income (loss)	$18.2	$37.1	$(5.5)	$(1.3)	$48.5

Three Months Ended June 30, 2011 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$108.0	$289.1	$168.3	$(135.3)	$430.1
Cost of goods sold	69.5	210.9	170.4	(134.4)	316.4
Gross margin on revenues	38.5	78.2	(2.1)	(0.9)	113.7
Other operation and maintenance	13.0	26.3	2.0	(0.7)	40.6
Depreciation and amortization	5.8	13.4	0.1	—	19.3
Taxes other than income	3.3	1.7	(0.1)	—	4.9
Operating income (loss)	$16.4	$36.8	$(4.1)	$(0.2)	$48.9

Six Months Ended June 30, 2012 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$154.2	$570.9	$206.6	$(158.1)	$773.6
Cost of goods sold	80.9	396.5	206.7	(156.2)	527.9
Gross margin on revenues	73.3	174.4	(0.1)	(1.9)	245.7
Other operation and maintenance	21.4	60.0	4.4	(0.8)	85.0
Depreciation and amortization	10.6	36.4	0.7	—	47.7
Impairment of assets	—	0.3	—	—	0.3
Gain on insurance proceeds	—	(7.5)	—	—	(7.5)
Taxes other than income	8.2	4.6	0.2	—	13.0
Operating income (loss)	$33.1	$80.6	$(5.4)	$(1.1)	$107.2

Six Months Ended June 30, 2011 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$208.2	$555.8	$366.4	$(257.9)	$872.5
Cost of goods sold	133.5	407.2	369.7	(255.7)	654.7
Gross margin on revenues	74.7	148.6	(3.3)	(2.2)	217.8
Other operation and maintenance	22.1	53.1	4.1	(1.5)	77.8

Depreciation and amortization	11.2	26.9	0.1	—	38.2
Taxes other than income	7.6	3.6	0.1	—	11.3
Operating income (loss)	$33.8	$65.0	$(7.6)	$(0.7)	$90.5

Operating Data

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Gathered volumes – TBtu/d	1.40	1.36	1.37	1.33
Incremental transportation volumes – TBtu/d (A)	0.69	0.56	0.61	0.54
Total throughput volumes – TBtu/d	2.09	1.92	1.98	1.87
Natural gas processed – TBtu/d	0.98	0.76	0.95	0.76
NGLs sold (keep-whole) – million gallons	37	42	73	84
NGLs sold (purchased for resale) – million gallons	156	112	311	224
NGLs sold (percent-of-liquids) – million gallons	7	6	13	12
NGLs sold (percent-of-proceeds) – million gallons	3	1	7	2
Total NGLs sold – million gallons	203	161	404	322
Average NGLs sales price per gallon	$0.83	$1.24	$0.91	$1.17
Average natural gas sales price per MMBtu	$2.23	$4.36	$2.49	$4.25

(A) Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

Three Months Ended June 30, 2012 as Compared to Three Months Ended June 30, 2011

Enogex's operating income decreased $0.4 million, or 0.8 percent, during the three months ended June 30, 2012 as compared to the same period in 2011. This decrease was primarily due to higher other operation and maintenance expense and higher depreciation and amortization expense partially offset by a higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from certain gas gathering assets acquired in November 2011 and (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant and from the South Canadian natural gas processing plant, which was placed in service in December 2011. These increases in gross margin were partially offset by lower average natural gas prices and lower average NGLs prices. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OER. During the three months ended June 30, 2012, imbalance volume changes and realized margin on physical gas long/short positions decreased the gross margin by $2.2 million, net of corresponding imbalance and fuel tracker balances.

Other operation and maintenance expense increased $2.2 million, or 5.4 percent, primarily due to increased payroll and benefits costs due to increased headcount to support business growth partially offset by lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during the three months ended June 30, 2012.

Depreciation and amortization expense increased $5.0 million, or 25.9 percent, primarily due to additional assets placed in service throughout 2011 and the six months ended June 30, 2012.

Transportation and Storage

The transportation and storage business contributed $37.7 million of Enogex's consolidated gross margin during the three months ended June 30, 2012 as compared to $38.5 million during the same period in 2011, a decrease of $0.8 million or 2.1 percent. The transportation operations contributed $30.7 million of Enogex's consolidated gross margin during the three months ended June 30, 2012 as compared to $31.0 million during the same period in 2011. The storage operations contributed $7.0 million of Enogex's consolidated gross margin during the three months ended

June 30, 2012 as compared to $7.5 million during the same period in 2011. Gross margin decreased primarily due to lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations, which decreased the gross margin by $2.1 million, net of imbalances and fuel tracker balances.

Other operation and maintenance expense for the transportation and storage business was $2.4 million, or 18.5 percent, lower during the three months ended June 30, 2012 as compared to the same period in 2011 primarily due to lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during the three months ended June 30, 2012.

Gathering and Processing

The gathering and processing business contributed $87.8 million of Enogex's consolidated gross margin during the three months ended June 30, 2012 as compared to $78.2 million during the same period in 2011, an increase of $9.6 million, or 12.3 percent. The gathering operations contributed $36.9 million of Enogex's consolidated gross margin during the three months ended June 30, 2012 as compared to $29.9 million during the same period in 2011. The processing operations contributed $50.9 million of Enogex's consolidated gross margin during the three months ended June 30, 2012 as compared to $48.3 million during the same period in 2011.

During the three months ended June 30, 2012, Enogex realized a higher gross margin in its gathering and processing operations related to (i) increased gathering rates and volumes associated with ongoing expansion projects, primarily in the Granite Wash play, which has added richer natural gas to Enogex's system, and increased volumes from certain gas gathering assets acquired in November 2011 and (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant and from the South Canadian natural gas processing plant, which was placed in service in December 2011. These increases in gross margin were partially offset by lower average natural gas prices, lower average NGLs prices and the contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011. Overall, the above factors resulted in an increased gross margin on fixed-fee contracts of $4.3 million and an increased gross margin on keep-whole processing of $2.9 million partially offset by a decrease in percent-of-liquids and percent-of-proceeds margins of $3.6 million.

The above factors contributed to the increase in the gathering and processing gross margin as follows:

- an increase in gathering fees associated with ongoing expansion projects and increased volumes from certain gas gathering assets acquired in November 2011, which increased the gross margin by $3.9 million;
- an increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $3.2 million; and
- an increase in residue gas sales related to a new percent-of-proceeds contract effective in July 2011, which increased the gross margin by $1.2 million.

These increases in the gathering and processing gross margin were partially offset by an increase in the utilization of third-party processing as a result of (i) the Atoka processing plant being taken out of service in August 2011 and (ii) increased activity from western Oklahoma and Texas panhandle expansion projects currently processed by third parties, which together decreased the gross margin by $1.8 million.

Other operation and maintenance expense for the gathering and processing business was $3.6 million, or 13.7 percent, higher during the three months ended June 30, 2012 as compared to the same period in 2011 primarily due to increased payroll and benefits costs due to increased headcount to support business growth.

Marketing

The marketing business recognized a loss of $2.9 million as part of Enogex's consolidated gross margin during the three months ended June 30, 2012 as compared to a loss of $2.1 million during the same period in 2011, a decrease in the gross margin of $0.8 million.

Enogex Consolidated Information

Other Income. Enogex's consolidated other income was less than $0.1 million during the three months ended June 30, 2012 as compared to $3.8 million during the same period in 2011, a decrease of $3.8 million, due to the recognition in April 2011 of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets.

Interest Expense. Enogex's consolidated interest expense was $7.4 million during the three months ended June 30, 2012 as compared to $5.7 million during the same period in 2011, an increase of $1.7 million, or 29.8 percent, primarily due to a higher outstanding balance under Enogex's revolving credit agreement during the three months ended June 30, 2012 as compared to the same period in 2011.

Income Tax Expense. Enogex's consolidated income tax expense was $12.6 million during the three months ended June 30, 2012 as compared to $15.5 million during the same period in 2011, a decrease of $2.9 million, or 18.7 percent, primarily due to lower pre-tax income during the three months ended June 30, 2012 as compared to the same period in 2011.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $7.5 million during the three months ended June 30, 2012 as compared to $6.4 million during the same period in 2011, an increase of $1.1 million or 17.2 percent, due to the ArcLight group's increased ownership percentage of membership interests in Enogex Holdings as a result of the ArcLight group funding capital contributions at a disproportionate percentage to OGE Holdings throughout 2011 partially offset by lower net income.

Non-Recurring Item. During the three months ended June 30, 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

Six Months Ended June 30, 2012 as Compared to Six Months Ended June 30, 2011

Enogex's operating income increased $16.7 million, or 18.5 percent, during the six months ended June 30, 2012 as compared to the same period in 2011. This increase was primarily due to a higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from certain gas gathering assets acquired in November 2011 and (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant and from the South Canadian natural gas processing plant, which was placed in service in December 2011. These increases in gross margin were partially offset by lower average natural gas prices and lower average NGLs prices. Also contributing to the increase in operating income was insurance proceeds received related to the damaged train at the Cox City natural gas processing plant discussed below. These increases were partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense. During the six months ended June 30, 2012, imbalance volume changes and realized margin on physical gas long/short positions decreased the gross margin by $1.3 million, net of corresponding imbalance and fuel tracker balances and the impact of the recovery of prior years' under-recovered fuel positions during the six months ended June 30, 2012.

Other operation and maintenance expense increased $7.2 million, or 9.3 percent, primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth;
- increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects during the six months ended June 30, 2012; and
- increased rental expense on compression associated with the acquisition of certain gas gathering assets in November 2011 partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

These increases were partially offset by decreased costs for soil remediation projects.

Depreciation and amortization expense increased $9.5 million, or 24.9 percent, primarily due to additional assets placed in service throughout 2011 and the six months ended June 30, 2012.
Gain on insurance proceeds was $7.5 million during the six months ended June 30, 2012 with no comparable item during the same period in 2011. The gain on insurance proceeds was related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant.

Taxes other than income expense increased $1.7 million, or 15.0 percent, primarily due to increased ad valorem taxes resulting from additional assets placed in service throughout 2011 and the six months ended June 30, 2012.

Transportation and Storage

The transportation and storage business contributed $73.3 million of Enogex's consolidated gross margin during the six months ended June 30, 2012 as compared to $74.7 million during the same period in 2011, a decrease of $1.4 million or 1.9 percent. The transportation operations contributed $62.5 million of Enogex's consolidated gross margin during the six months ended June 30, 2012 as compared to $59.1 million during the same period in 2011. The storage operations contributed $10.8 million of Enogex's consolidated gross margin during the six months ended June 30, 2012 as compared to $15.6 million during the same period in 2011. Gross margin decreased primarily due to the recognition of a $4.0 million lower of cost or market adjustment on natural gas inventory held in storage during the six months ended June 30, 2012, partially offset by higher transportation demand fees as a result of new contracts, which increased the gross margin by $3.6 million.

Gathering and Processing

The gathering and processing business contributed $174.4 million of Enogex's consolidated gross margin during the six months ended June 30, 2012 as compared to $148.6 million during the same period in 2011, an increase of $25.8 million, or 17.4 percent. The gathering operations contributed $67.7 million of Enogex's consolidated gross margin during the six months ended June 30, 2012 as compared to $58.3 million during the same period in 2011. The processing operations contributed $106.7 million of Enogex's consolidated gross margin during the six months ended June 30, 2012 as compared to $90.3 million during the same period in 2011.

During the six months ended June 30, 2012, Enogex realized a higher gross margin in its gathering and processing operations related to (i) increased gathering rates and volumes associated with ongoing expansion projects, primarily in the Granite Wash play, which has added richer natural gas to Enogex's system, and increased volumes from certain gas gathering assets acquired in November 2011 and (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant and from the South Canadian natural gas processing plant, which was placed in service in December 2011. These increases in gross margin were partially offset by lower average natural gas prices, lower average NGLs prices and the contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011. Overall, the above factors resulted in an increased gross margin on keep-whole processing of $11.9 million and an increased gross margin on fixed-fee contracts of $6.6 million partially offset by a decrease in percent-of-liquids and percent-of-proceeds margins of $4.4 million.

The above factors contributed to the increase in the gathering and processing gross margin as follows:

- an increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $8.7 million;
- an increase in gathering fees associated with ongoing expansion projects and increased volumes from certain gas gathering assets acquired in November 2011, which increased the gross margin by $6.6 million; and
- an increase in residue gas sales related to a new percent-of-proceeds contract effective in July 2011, which increased the gross margin by $2.1 million.

These increases in the gathering and processing gross margin were partially offset by:

- an increase in the utilization of third-party processing as a result of (i) the Atoka processing plant being taken out of service in August 2011 and (ii) increased activity from western Oklahoma and Texas panhandle expansion projects currently processed by third parties, which together decreased the gross margin by $4.3 million; and
- lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin by $1.0 million, net of imbalances and fuel tracker obligations.

Other operation and maintenance expense for the gathering and processing business was $6.9 million, or 13.0 percent, higher during the six months ended June 30, 2012 as compared to the same period in 2011 primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth;
- increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects during the six months ended June 30, 2012; and
- increased rental expense on compression associated with the acquisition of certain gas gathering assets in November 2011 partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

These increases were partially offset by decreased costs for soil remediation projects.

Marketing

The marketing business recognized a loss of $0.1 million as part of Enogex's consolidated gross margin during the six months ended June 30, 2012 as compared to a loss of $3.3 million during the same period in 2011, an increase in the gross margin of $3.2 million, or 97.0 percent, primarily due to a higher realized margin on the sale of natural gas inventory from storage and associated hedging activity and recovering lower of cost or market adjustments recorded on the inventory in the second half of 2011, which increased the gross margin by $3.3 million.

Enogex Consolidated Information

Other Income. Enogex's consolidated other income was $0.2 million during the six months ended June 30, 2012 as compared to $4.0 million during the same period in 2011, a decrease of $3.8 million, or 95.0 percent, due to the recognition in April 2011 of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets.

Interest Expense. Enogex's consolidated interest expense was $15.0 million during the six months ended June 30, 2012 as compared to $12.1 million during the same period in 2011, an increase of $2.9 million, or 24.0 percent, primarily due to a higher outstanding balance under Enogex's revolving credit agreement during the six months ended June 30, 2012 as compared to the same period in 2011.

Income Tax Expense. Enogex's consolidated income tax expense was $27.9 million during the six months ended June 30, 2012 as compared to $26.9 million during the same period in 2011, an increase of $1.0 million, or 3.7 percent, primarily due to higher pre-tax income during the six months ended June 30, 2012 as compared to the same period in 2011.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $17.9 million during the six months ended June 30, 2012 as compared to $11.2 million during the same period in 2011, an increase of $6.7 million or 59.8 percent, due to higher net income and the ArcLight group's increased ownership percentage of membership interests in Enogex Holdings as a result of the ArcLight group funding capital contributions at a disproportionate percentage to OGE Holdings throughout 2011.

Non-Recurring Item. During the six months ended June 30, 2012, Enogex had an increase in net income of $4.6 million for a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant, which Enogex does not consider to be reflective of its ongoing performance. During the six months ended June 30, 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

Non-GAAP Financial Measure

Enogex has included in this Form 10-Q the non-GAAP financial measure EBITDA. EBITDA is a supplemental non-GAAP financial measure used by external users of the Company's financial statements such as investors, commercial banks and others, to assess:

- the financial performance of Enogex's assets without regard to financing methods, capital structure or historical cost basis;
- Enogex's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Enogex provides a reconciliation of EBITDA to net income attributable to Enogex Holdings, which Enogex considers to be its most directly comparable financial measure as calculated and presented in accordance with GAAP. The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net income attributable to Enogex Holdings. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. EBITDA should not be considered in isolation or as a substitute for analysis of Enogex's results as reported under GAAP. Because EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in Enogex's industry, Enogex's definition of EBITDA may not be comparable to a similarly titled measure of other companies.

To compensate for the limitations of EBITDA as an analytical tool, Enogex believes it is important to review the comparable GAAP measure and understand the differences between the measures.

Reconciliation of EBITDA to net income attributable to Enogex Holdings

(In millions)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net income attributable to Enogex Holdings	$41.2	$46.7	$90.7	$81.2
Add:				
Interest expense, net	7.4	5.6	15.0	12.0
Income tax expense (A)	—	—	0.1	0.1
Depreciation and amortization expense (B)	25.0	19.0	49.1	37.6
EBITDA	$73.6	$71.3	$154.9	$130.9
OGE Energy's portion	$59.8	$61.8	$125.9	$114.1

(A) As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.
(B) Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera Energy Partners III, LLC in November 2011, which is included in gross margin for financial reporting purposes.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,391 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Liquidity and Capital Resources

Working Capital

Working capital is defined as the amount by which current assets exceed current liabilities. The Company's working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, the level and timing of spending for maintenance and expansion activity, inventory levels and fuel recoveries.

The balance of Accounts Receivable, Net, and Accrued Unbilled Revenues was $387.2 million and $381.8 million at June 30, 2012 and December 31, 2011, respectively, an increase of $5.4 million, or 1.4 percent, primarily due to an increase in billings to OG&E's customers reflecting higher usage due to warmer weather and higher seasonal electric rates in June 2012 as compared to December 2011 partially offset by a decrease at Enogex due to lower natural gas sales volumes and prices and the timing of customer payments received.

The balance of Accounts Payable was $274.5 million and $388.0 million at June 30, 2012 and December 31, 2011, respectively, a decrease of $113.5 million, or 29.3 percent, primarily due to payments made in 2012 for projects accrued at December 31, 2011, the timing of outstanding checks clearing the bank and lower natural gas prices and volumes at Enogex.

Cash Flows

(In millions)	Six Months Ended June 30, 2012	2011	$ Change	% Change
Net cash provided from operating activities	$281.5	$246.5	$35.0	14.2 %
Net cash used in investing activities	(526.9)	(532.7)	5.8	(1.1)%
Net cash provided from financing activities	242.5	289.0	(46.5)	(16.1)%

Operating Activities

The increase in net cash provided from operating activities during the six months ended June 30, 2012 as compared to the same period in 2011 was primarily due to higher fuel recoveries at OG&E in the first half of 2012 as compared to the same period in 2011 and an increase in cash received in 2012 from the recovery of investments including the Crossroads wind farm, the Windspeed transmission line, Smart Grid, the OU Spirit wind farm and system hardening as well as a decrease in purchases and sales at Enogex due to lower natural gas prices and NGLs prices partially offset by an increase in gathered volumes and NGLs volumes during the six months ended June 30, 2012 as compared to the same period in 2011.

Investing Activities

The decrease in net cash used in investing activities during the six months ended June 30, 2012 as compared to the same period in 2011 primarily related to lower levels of capital expenditures in 2012 related to the Crossroads wind farm at OG&E partially offset by higher levels of capital expenditures related to gathering and processing expansion projects at Enogex.

Financing Activities

The decrease in net cash provided from financing activities during the six months ended June 30, 2012 as compared to the same period in 2011 was primarily due to proceeds received from the issuance of long-term debt during the six months ended June 30, 2011 as well as a contribution from the ArcLight group during the six months ended June 30, 2011 partially offset by an increase in short-term debt borrowings during the six months ended June 30, 2012 as compared to the same period in 2011 and repayments of Enogex's line of credit during the six months ended June 30, 2011.

Future Capital Requirements and Financing Activities

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, hedging activities, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2012 through 2016 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects.

(In millions)	2012	2013	2014	2015	2016
OG&E Base Transmission	$70	$50	$50	$50	$50
OG&E Base Distribution	175	175	175	175	175
OG&E Base Generation	75	75	75	75	75
OG&E Other	20	15	15	15	15
Total OG&E Base Transmission, Distribution, Generation and Other	340	315	315	315	315
OG&E Known and Committed Projects:					
Transmission Projects:					
Sunnyside-Hugo (345 kilovolt)	25	—	—	—	—
Sooner-Rose Hill (345 kilovolt)	5	—	—	—	—
Balanced Portfolio 3E Projects	115	180	50	—	—
SPP Priority Projects	20	200	115	—	—
Total Transmission Projects	165	380	165	—	—
Other Projects:					
Smart Grid Program (A)	90	30	30	15	15
Crossroads Wind Farm	40	—	—	—	—
System Hardening	10	15	—	—	—
Environmental - low NOX burners	10	45	20	25	20
Total Other Projects	150	90	50	40	35
Total OG&E Known and Committed Projects	315	470	215	40	35
Total OG&E (B)	655	785	530	355	350
Enogex LLC Base Maintenance	55	55	55	55	55
Enogex LLC Known and Committed Projects:					
Western Oklahoma / Texas Panhandle Gathering Expansion	470	250	20	15	5
Other Gathering Expansion	20	15	15	15	15
Total Enogex LLC Known and Committed Projects	490	265	35	30	20
Total Enogex LLC (C)	545	320	90	85	75
OGE Energy	15	10	10	10	10
Total capital expenditures	$1,215	$1,115	$630	$450	$435

(A) These capital expenditures are net of the $130 million Smart Grid grant approved by the U.S. Department of Energy.

(B) The capital expenditures above exclude any environmental expenditures associated with:

- Pollution control equipment related to controlling SO2 emissions under the regional haze requirements due to the uncertainty regarding the approach and timing for such pollution control equipment. The SO2 emissions standards in the EPA's FIP could require the installation of Dry Scrubbers or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. The FIP is being challenged by OG&E and the state of Oklahoma. On June 22, 2012, OG&E was granted a stay of the FIP by the U.S. Court of Appeals for the Tenth Circuit, which delays the timing of required implementation of the SO2 emissions standards in the rule. Neither the outcome of the challenge to the FIP nor the timing of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant.
- Compliance with Maximum Achievable Control Technology requirements due to the uncertainty regarding the approach and timing of such expenditures. OG&E is planning to utilize dry sorbent injection with activated carbon injection at up to five coal-fired units at an estimated cost of $310 million, but the timing of such expenditures is uncertain.

OG&E is currently evaluating options to comply with environmental requirements. For further information, see "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" below.

(C) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion may be funded by the ArcLight group. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex LLC, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex LLC in the table above reflect base market conditions at August 2, 2012 and do not reflect the potential opportunity for a set of growth projects that could materialize. Also, if drilling activity declines in the future, this could reduce Enogex's capital expenditures in the table above.

Security Ratings

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit. In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at June 30, 2012, the Company would have been required to post $0.1 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at June 30, 2012. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral. On June 20, 2012, Fitch Ratings downgraded OGE Energy Corp.'s short-term debt rating from F1 to F2 and OGE Energy Corp.'s long-term debt issuer default rating from A to A-. All other ratings (by Fitch Ratings) at OG&E and Enogex remained unchanged and with a stable outlook. Fitch Ratings indicated that the downgrade at OGE Energy Corp. was primarily due to concerns related to the uncertainties associated with the environmental mandates at OG&E as well as Enogex's sensitivity to commodity prices and growth strategy with the ArcLight group.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. Additionally, the Company will have an additional source of funding for growth opportunities at Enogex through the ArcLight group and from quarterly distributions from Enogex Holdings. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The Company has revolving credit facilities totaling in the aggregate $1,550.0 million. These bank facilities can also be used as letter of credit facilities. The short-term debt balance was $596.7 million and $277.1 million at June 30, 2012 and December 31, 2011, respectively. The weighted-average interest rate on short-term debt at June 30, 2012 was 0.46 percent. The average balance of short-term debt during the three months ended June 30, 2012 was $550.7 million at a weighted-average interest rate of 0.46 percent. The maximum month-end balance of short-term debt during the three months ended June 30, 2012 was $596.7 million. At June 30, 2012, OG&E had $2.2 million in letters of credit at a weighted-average interest rate of 0.53 percent. At both June 30, 2012 and December 31, 2011, Enogex had $150.0 million in outstanding borrowings under its revolving credit agreement. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Condensed Consolidated Balance Sheets. At June 30, 2012, the Company had $801.1 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2011 and ending December 31, 2012. At June 30, 2012, the Company had $1.7 million in cash and cash equivalents. See Note 9 of Notes to Condensed Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Expected Issuance of Enogex Debt

Depending on market conditions, Enogex expects to utilize up to $250 million of debt financing during the third quarter of 2012, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

Critical Accounting Policies and Estimates

The Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Condensed Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Condensed Consolidated Financial Statements. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised for all Company segments includes the valuation of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets), income taxes, contingency reserves, asset retirement obligations, fair value and cash flow hedges and the allowance for uncollectible accounts receivable. For the electric utility segment, the most significant judgment is also exercised in the valuation of regulatory assets and liabilities and unbilled revenues. For the natural gas transportation and storage, gathering and processing and marketing segments, the most significant judgment is also exercised in the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment, amortization methodologies related to intangible assets and impairment assessments of goodwill. The selection, application and disclosure of the Company's critical accounting estimates have been discussed with the Company's Audit Committee and are discussed in detail in Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's 2011 Form 10-K.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. At the present time, based on currently available information, except as otherwise stated in Notes 12 and 13 of Notes to Condensed Consolidated Financial Statements, under "Environmental Laws and Regulations" below and in Item 1 of Part II of this Form 10-Q, in Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I of the Company's 2011 Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Environmental Laws and Regulations

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way they can handle or dispose of their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards. These environmental laws and regulations are discussed in detail in Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's 2011 Form 10-K. Except as set forth below, there have been no material changes to such items.

OG&E expects that environmental expenditures necessary to comply with the environmental laws and regulations discussed below will qualify as part of a pre-approval plan to handle state and Federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

Air

Regional Haze Control Measures

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. The regional haze rule is intended to protect visibility in certain national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the rule. However, Oklahoma's impact on parks in other states must also be evaluated.

As required by the Federal regional haze rule, the state of Oklahoma evaluated the installation of BART to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. Certain of OG&E’s units at the Horseshoe Lake, Seminole, Muskogee and Sooner generating stations were evaluated for BART. On February 18, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The SIP was subject to the EPA's review and approval.

The Oklahoma SIP included requirements for reducing emissions of NOX and SO2 from OG&E's seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations. The SIP also included a waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners with overfire air (flue gas recirculation was also required on two of the units) and set forth associated NOX emission rates and limits. OG&E preliminarily estimates that the total capital cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be approximately $120 million. With respect to SO2 emissions, the SIP included an agreement between the Oklahoma Department of Environmental Quality and OG&E that established BART for SO2 control at four coal-fired units located at OG&E's Sooner and Muskogee generating stations as the continued use of low sulfur coal (along with associated emission rates and limits). The SIP specifically rejected the installation and operation of Dry Scrubbers as BART for SO2 control from these units because the state determined that Dry Scrubbers were not cost effective on these units.

On December 28, 2011, the EPA issued a final rule in which it rejected portions of the Oklahoma SIP and issued a FIP in their place. While the EPA accepted Oklahoma's BART determination for NOX in the final rule, it rejected Oklahoma's SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. The EPA is instead requiring that OG&E meet an SO2 emission rate of 0.06 pounds per MMBtu within five years. OG&E could meet the proposed standard by either installing and operating Dry Scrubbers or fuel switching at the four affected units. OG&E estimates that installing Dry Scrubbers on these units would include capital costs to OG&E of more than $1.0 billion. OG&E and the state of Oklahoma filed an administrative stay request with the EPA on February 24, 2012. The EPA has not yet responded to this request. OG&E and other parties also filed a petition for review of the FIP in the U.S. Court of Appeals for the Tenth Circuit on February 24, 2012 and a stay request on April 4, 2012. On June 22, 2012, the U.S. Court of Appeals for the Tenth Circuit granted the stay request. The stay will remain in place until a decision on the petition for review is complete, which will delay the implementation of the regional haze rule in Oklahoma. On June 15, 2012, OG&E, the state of Oklahoma and other parties filed their brief in support of the petition for review of the final regional haze rule of the EPA. The briefing by all parties is currently scheduled to be completed in October 2012. Neither the outcome of the appeal nor the timing of any required expenditures for pollution control equipment can be predicted with any certainty at this time.

Cross-State Air Pollution Rule

On July 7, 2011, the EPA finalized its Cross-State Air Pollution Rule to replace the former Clean Air Interstate Rule that was remanded by a Federal court as a result of legal challenges. The final rule requires 27 states to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. On December 27, 2011, the EPA published a supplemental rule, which makes six additional states, including Oklahoma, subject to the Cross-State Air Pollution Rule for NOX emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E is required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. The Cross-State Air Pollution Rule is currently being challenged in court by numerous states and power generators. On December 30, 2011, the U.S. Court of Appeals issued a stay of the rule, which includes the supplemental rule, pending a decision on the merits. In April 2012, the U.S. Court of Appeals heard oral arguments on this rule but has not yet issued its decision. OG&E cannot predict the outcome of such challenges and is evaluating what emission controls would be necessary to meet the standards, its ability to comply with the standards in the timeframe proposed by the EPA and the associated costs, which could be significant.

Hazardous Air Pollutants Emission Standards

On December 16, 2011, the EPA signed the Maximum Achievable Control Technology regulations governing emissions of certain hazardous air pollutants from electric generating units. The final rule includes numerical standards for particulate matter (as a surrogate for toxic metals), hydrogen chloride and mercury emissions from coal-fired boilers. In addition, the regulations include work practice standards for dioxins and furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years after the effective date of the rule with a likely possibility of a one year extension. To comply with this rule, OG&E is planning to utilize dry sorbent injection with activated carbon injection at up to five coal-fired units at an estimated capital cost of $310 million, but the timing of such expenditures is uncertain. The final rule has been appealed by several parties. OG&E is not a party to these appeals. OG&E cannot predict the outcome of any such appeals. OG&E is planning to conduct field testing to develop firm cost estimates and implementation schedules.

Notice of Violation

In July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. On May 1, 2012, OG&E responded to the EPA's supplemental request for information. OG&E believes it has acted in full compliance with the Federal Clean Air Act and new source review process and is cooperating with the EPA. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects that occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards. OG&E has met with the EPA regarding the notice but cannot predict at this time what, if any, further actions may be necessary as a result of the notice. The EPA could seek to require OG&E to install additional pollution control equipment and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation. The cost of any required pollution control equipment could also be significant.

Climate Change and Greenhouse Gas Emissions

On June 3, 2010, the EPA issued a final rule that makes certain sources subject to permitting requirements for greenhouse gas emissions. This rule now requires sources that emit greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. Such sources may have to install best available control technology to control greenhouse gas emissions pursuant to this rule. Also, in December 2010, the EPA entered into an agreement to settle litigation brought by states and environmental groups whereby the EPA agreed to issue New Source Performance Standards for greenhouse gas emissions from certain new and modified electric generating units and emissions guidelines for existing units over the next two years. Pursuant to this settlement agreement, the EPA agreed to issue proposed rules during the fourth quarter of 2011 and final rules by mid-2012. On March 27, 2012, the EPA proposed a new source performance standards limit of 1,000 pounds of carbon dioxide per megawatt-hour. The proposed limit would apply only to new sources. The EPA did not propose standards for existing or modified sources.

Water

With respect to cooling water intake structures, Section 316(b) of the Federal Clean Water Act requires that their location, design, construction and capacity reflect the "best available technology" for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. In March 2011, the EPA proposed rules to implement Section 316(b). On August 18, 2011, OG&E filed comments with the EPA on the proposed rules. In June 2012, the EPA published a Notice of Data Availability requesting additional comments on a number of impingement mortality-related issues based on new information received during the initial public comment period. On July 11, 2012, OG&E filed comments regarding the Notice of Data Availability. In June 2012, the EPA entered into a settlement agreement in a pending litigation matter, which extended the deadline by which the proposed rules will be finalized to June 2013. In the interim, the state of Oklahoma requires OG&E to implement best management practices related to the operation and maintenance of its existing cooling water intake structures as a condition of renewing its discharge permits. Once the EPA promulgates the final rules, OG&E may incur additional capital and/or operating costs to comply with them. The costs of complying with the final water intake standards are not currently determinable, but could be significant.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, the market risks set forth in Part II, Item 7A of the Company's 2011 Form 10-K appropriately represent, in all material respects, the market risks affecting the Company.

Commodity Price Risk

The commodity price risks inherent in the Company's commodity price sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the commodity prices to which the

Company is exposed. These risks can be classified as trading, which includes transactions that are entered into voluntarily to capture subsequent changes in commodity prices, or non-trading, which includes the exposure some of the Company's assets have to commodity prices.

Trading activities are conducted throughout the year subject to $2.5 million daily and monthly trading stop loss limits set by the Risk Oversight Committee. The loss exposure from trading activities is measured primarily using value-at-risk, which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. Currently, the Company utilizes the variance/co-variance method for calculating value-at-risk, assuming a 95 percent confidence level. The value-at-risk limit set by the Risk Oversight Committee for the Company's trading activities is currently $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each net commodity position based upon quoted market prices. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $0.1 million at June 30, 2012. This amount represents the Company's exposure, net of the ArcLight group's proportional share.

Commodity price risk is present in the Company's non-trading activities because changes in the prices of natural gas, NGLs and NGLs processing spreads have a direct effect on the compensation the Company receives for operating some of its assets. These prices are subject to fluctuations resulting from changes in supply and demand. To partially reduce non-trading commodity price risk, the Company utilizes risk mitigation tools such as default processing fees and ethane rejection capabilities to protect its downside exposure while maintaining its upside potential. Additionally, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the Company's operating income. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company's non-trading positions; therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forward price curves. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $24.4 million at June 30, 2012. This decrease is due to the decline in forward price curves for NGLs. These amounts represent the Company's exposure, net of the ArcLight group's proportional share.

Item 4. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the chief executive officer and chief financial officer, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Reference is made to Item 3 of Part I of the Company's 2011 Form 10-K for a description of certain legal proceedings presently pending. Except as set forth below, there are no new significant cases to report against the Company or its subsidiaries and there have been no material changes in the previously reported proceedings.

1. Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of OGE Energy were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-Federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended class action petition, and the court granted the motion on July 28, 2003. In its amended petition, OG&E and Enogex Inc. were omitted from the case but two of OGE Energy's other subsidiary entities remained as defendants. The plaintiffs' amended petition seeks class certification and alleges that 60 defendants, including two of OGE Energy's subsidiary entities, have improperly measured the volume of natural gas. The amended petition asserts theories of civil conspiracy, aiding and abetting, accounting and unjust enrichment. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims. On February 7, 2012, Enogex LLC and OER filed an application in the Kansas Court of Appeals seeking appeal of the trial court's denial of their motions for summary judgment. On February 23, 2012, the Kansas Court of Appeals denied this application. On March 23, 2012, Enogex LLC and OER filed an application with the Kansas Supreme Court seeking appeal of the Kansas Court of Appeals' decision. On July 19, 2012, the plaintiffs filed a motion to dismiss Enogex LLC and OER from the action. At this time, based on currently available information, OGE Energy does not believe it is reasonably possible that it will incur a material loss related to these proceedings and, therefore, OGE Energy does not believe the outcome will have a material impact on its financial position, results of operations or cash flows.

2. Will Price, et al. v. El Paso Natural Gas Co., et al. (Price II). On May 12, 2003, the plaintiffs (same as those in the amended petition in Price I above) filed a new class action petition in the District Court of Stevens County, Kansas naming the same defendants and asserting substantially identical legal and/or equitable theories as in the amended petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two of OGE Energy's other subsidiary entities were named in this case. The plaintiffs allege that the defendants mismeasured the British thermal unit content of natural gas obtained from or measured for the plaintiffs. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims. On February 7, 2012, Enogex LLC and OER filed an application in the Kansas Court of Appeals seeking appeal of the trial court's denial of their motions for summary judgment. On February 23, 2012, the Kansas Court of Appeals denied this application. On March 23, 2012, Enogex LLC and OER filed an application with the Kansas Supreme Court seeking appeal of the Kansas Court of Appeals' decision. On July 19, 2012, the plaintiffs filed a motion to dismiss Enogex LLC and OER from the action. At this time, based on currently available information, OGE Energy does not believe it is reasonably possible that it will incur a material loss related to these proceedings and, therefore, OGE Energy does not believe the outcome will have a material impact on its financial position, results of operations or cash flows.

Item 1A. Risk Factors.

There have been no significant changes in the Company's risk factors from those discussed in the Company's 2011 Form 10-K, which are incorporated herein by reference.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

The following table contains information about the Company's purchases of its common stock during the second quarter of 2012.

Period	Total Number of Shares Purchased		Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
4/1/12-4/30/12	2,587	(A)	$52.41	N/A	N/A
5/1/12-5/31/12	—		$—	N/A	N/A
6/1/12-6/30/12	—		$—	N/A	N/A

(A) These shares were returned to the Company on behalf of certain participants receiving restricted stock to effectuate the payment of Federal and state income taxes on the award.
N/A - not applicable

Item 6. Exhibits.

Exhibit No.	Description
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 9, 2012 (File No. 1-12579) and incorporated by reference herein).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

SIGNATURE

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.

OGE ENERGY CORP.
(Registrant)

By: /s/ Scott Forbes
Scott Forbes
Controller and Chief Accounting Officer
(On behalf of the Registrant and in his capacity as Chief Accounting Officer)

August 2, 2012