OGE ENERGY CORP.
Form 10-Q
November 03, 2011

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 September 30, 2011
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 (State or other jurisdiction of incorporation or organization)	73-1481638 (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 September 30, 2011, there were 98,056,722 shares of common stock, par value $0.01 per share, outstanding.

Table of Contents

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2011

TABLE OF CONTENTS

Table of Contents

GLOSSARY OF TERMS

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

Abbreviation	Definition
2010 Form 10-K	Annual Report on Form 10-K for the year ended December 31, 2010
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
Company	OGE Energy, collectively with its subsidiaries
Cordillera	Cordillera Energy Partners III, LLC
Crossroads	OG&E's Crossroads wind project in Dewey County, Oklahoma
Dry Scrubbers	Dry flue gas desulfurization units with Spray Dryer Absorber
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
GAAP	Accounting principles generally accepted in the United States
MEP	Midcontinent Express Pipeline, LLC
MMcf/d	Million cubic feet per day
NAAQS	National Ambient Air Quality Standards
NGLs	Natural gas liquids
NOX	Nitrogen oxide
NYMEX	New York Mercantile Exchange
OCC	Oklahoma Corporation Commission
ODEQ	Oklahoma Department of Environmental Quality
OER	OGE Energy Resources LLC, wholly-owned subsidiary of Enogex 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
Oxbow	Oxbow Midstream, LLC
Pension Plan	Qualified defined benefit retirement plan
PRM	Price risk management
Products	Enogex Products LLC, wholly-owned subsidiary of Enogex LLC
SIP	State implementation plan
SO2	Sulfur dioxide
SPP	Southwest Power Pool
System sales	Sales to OG&E's customers
Windspeed	OG&E's transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma

Table of Contents

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 2010 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;
- 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 2010 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.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2011	2010	2011	2010
OPERATING REVENUES				
Electric Utility operating revenues	$774.8	$723.0	$1,765.6	$1,679.8
Natural Gas Midstream Operations operating revenues	437.3	402.4	1,265.1	1,208.6
Total operating revenues	1,212.1	1,125.4	3,030.7	2,888.4
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)				
Electric Utility cost of goods sold	322.7	299.4	772.7	757.2
Natural Gas Midstream Operations cost of goods sold	335.8	313.2	969.1	932.0
Total cost of goods sold	658.5	612.6	1,741.8	1,689.2
Gross margin on revenues	553.6	512.8	1,288.9	1,199.2
OPERATING EXPENSES				
Other operation and maintenance	147.4	142.4	432.3	401.0
Depreciation and amortization	77.1	73.7	225.8	215.2
Impairment of assets	5.0	—	5.0	—
Taxes other than income	24.4	22.5	76.0	70.5
Total operating expenses	253.9	238.6	739.1	686.7
OPERATING INCOME	299.7	274.2	549.8	512.5
OTHER INCOME (EXPENSE)				
Interest income	0.2	—	0.4	—
Allowance for equity funds used during construction	5.9	2.6	16.1	7.2
Other income	(2.2)	0.6	11.1	5.8
Other expense	(6.4)	(2.7)	(12.2)	(8.8)
Net other income (expense)	(2.5)	0.5	15.4	4.2
INTEREST EXPENSE				
Interest on long-term debt	37.4	36.3	108.6	103.3
Allowance for borrowed funds used during construction	(2.9)	(1.3)	(8.1)	(3.5)
Interest on short-term debt and other interest charges	1.0	1.4	3.6	4.7
Interest expense	35.5	36.4	104.1	104.5
INCOME BEFORE TAXES	261.7	238.3	461.1	412.2
INCOME TAX EXPENSE	80.3	74.8	140.7	145.6
NET INCOME	181.4	163.5	320.4	266.6
Less: Net income attributable to noncontrolling interests	2.7	0.4	13.9	2.0
NET INCOME ATTRIBUTABLE TO OGE ENERGY	$178.7	$163.1	$306.5	$264.6
BASIC AVERAGE COMMON SHARES OUTSTANDING	98.0	97.4	97.9	97.3
DILUTED AVERAGE COMMON SHARES OUTSTANDING	99.3	99.0	99.2	98.8
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$1.82	$1.67	$3.13	$2.72

DILUTED EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$1.80	$1.65	$3.09	$2.68
DIVIDENDS DECLARED PER COMMON SHARE	$0.3750	$0.3625	$1.1250	$1.0875

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

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Net income	$181.4	$163.5	$320.4	$266.6
Other comprehensive income (loss), net of tax				
Pension Plan and Restoration of Retirement Income Plan:				
Amortization of deferred net loss, net of tax of $0.3 million, $0.4 million, $1.2 million and $1.4 million, respectively	0.7	0.6	1.7	1.6
Amortization of prior service cost, net of tax of $0, $0.1 million, $0 and $0.1 million, respectively	0.1	0.1	0.3	0.2
Postretirement plans:				
Amortization of deferred net loss, net of tax of $0.2 million, $0.2 million, $0.8 million and $0.2 million, respectively	0.5	0.3	1.3	1.2
Amortization of deferred net transition obligation, net of tax of $0, $0, $0 and $0.1 million, respectively	—	—	0.1	0.3
Amortization of prior service cost, net of tax of ($0.2) million, $0, ($0.8) million and ($0.1) million, respectively	(0.5)	—	(1.4)	(0.2)
Prior service cost arising during the period, net of tax of $0, $0, $6.2 million and $0, respectively	—	—	10.7	—
Deferred commodity contracts hedging losses reclassified in net income, net of tax of $3.4 million, $2.1 million, $10.3 million and $7.3 million, respectively	6.7	3.4	20.2	11.6
Deferred commodity contracts hedging gains (losses), net of tax of $0.1 million, ($6.6) million, ($2.7) million and ($5.6) million, respectively	0.2	(10.4)	(6.3)	(9.0)
Deferred interest rate swaps hedging gains, net of tax of $0, $0, $0.2 million and $0.1 million, respectively	—	—	0.2	0.1
Other comprehensive income (loss), net of tax	7.7	(6.0)	26.8	5.8
Comprehensive income (loss)	189.1	157.5	347.2	272.4
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	—	—	(1.7)	—
Less: Comprehensive income attributable to noncontrolling interests	4.2	0.4	17.7	2.0
Total comprehensive income (loss) attributable to OGE Energy	$184.9	$157.1	$331.2	$270.4

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

Table of Contents

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

	Nine Months Ended September 30,	
(In millions)	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$320.4	$266.6
Adjustments to reconcile net income to net cash provided from operating activities		
Depreciation and amortization	225.8	215.2
Impairment of assets	5.0	—
Deferred income taxes and investment tax credits, net	146.1	146.8
Allowance for equity funds used during construction	(16.1)	(7.2)
(Gain) loss on disposition and abandonment of assets	(2.8)	0.9
Stock-based compensation expense	3.4	4.9
Excess tax benefit on stock-based compensation	—	(0.7)
Price risk management assets	0.1	2.3
Price risk management liabilities	12.0	6.2
Regulatory assets	9.6	15.4
Regulatory liabilities	0.6	(10.3)
Other assets	(5.4)	5.4
Other liabilities	(41.3)	(10.9)
Change in certain current assets and liabilities		
Accounts receivable, net	(118.5)	(48.0)
Accrued unbilled revenues	(9.8)	(11.2)
Income taxes receivable	(3.6)	141.2
Fuel, materials and supplies inventories	61.5	(12.3)
Gas imbalance assets	(0.1)	—
Fuel clause under recoveries	(32.2)	(0.6)
Other current assets	7.1	7.8
Accounts payable	(40.9)	(13.7)
Gas imbalance liabilities	(1.1)	(1.0)
Fuel clause over recoveries	(21.4)	(119.5)
Other current liabilities	30.3	9.6
Net Cash Provided from Operating Activities	528.7	586.9
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures (less allowance for equity funds used during construction)	(907.3)	(612.5)
Reimbursement of capital expenditures	37.2	24.5
Proceeds from sale of assets	17.8	1.9
Other investing activities	—	0.1
Net Cash Used in Investing Activities	(852.3)	(586.0)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from long-term debt	246.3	246.2
Increase in short-term debt	144.0	49.0
Contributions from noncontrolling interest partners	73.5	—
Issuance of common stock	11.0	13.5
Proceeds from line of credit	—	115.0
Excess tax benefit on stock-based compensation	—	0.7

Retirement of long-term debt	—	(289.2)
Distributions to noncontrolling interest partners	(12.8)	—
Repayment of line of credit	(25.0)	(80.0)
Dividends paid on common stock	(110.1)	(105.7)
Net Cash Provided from (Used in) Financing Activities	326.9	(50.5)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	3.3	(49.6)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2.3	58.1
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$5.6	$8.5

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

Table of Contents

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$5.6	$2.3
Accounts receivable, less reserve of $2.4 and $1.9, respectively	396.4	277.9
Accrued unbilled revenues	66.6	56.8
Income taxes receivable	8.3	4.7
Fuel inventories	91.0	158.8
Materials and supplies, at average cost	89.6	83.3
Price risk management	1.8	1.4
Gas imbalances	2.6	2.5
Deferred income taxes	13.8	18.7
Fuel clause under recoveries	33.2	1.0
Other	17.6	24.7
Total current assets	726.5	632.1
OTHER PROPERTY AND INVESTMENTS, at cost	45.4	44.9
PROPERTY, PLANT AND EQUIPMENT		
In service	9,569.3	9,188.0
Construction work in progress	874.7	460.0
Total property, plant and equipment	10,444.0	9,648.0
Less accumulated depreciation	3,295.2	3,183.6
Net property, plant and equipment	7,148.8	6,464.4
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	415.3	489.4
Price risk management	0.3	0.8
Other	42.5	37.5
Total deferred charges and other assets	458.1	527.7
TOTAL ASSETS	$8,378.8	$7,669.1

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

Table of Contents

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(In millions)	September 30, 2011 (Unaudited)	December 31, 2010
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$289.0	$145.0
Accounts payable	297.4	321.7
Dividends payable	36.8	36.6
Customer deposits	68.0	67.0
Accrued taxes	61.6	39.3
Accrued interest	35.1	53.1
Accrued compensation	54.0	43.3
Price risk management	6.9	16.8
Gas imbalances	5.6	6.7
Fuel clause over recoveries	8.5	29.9
Other	71.3	55.1
Total current liabilities	934.2	814.5
LONG-TERM DEBT	2,586.9	2,362.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	241.5	372.4
Deferred income taxes	1,599.8	1,434.8
Deferred investment tax credits	6.9	9.4
Regulatory liabilities	223.2	193.1
Price risk management	0.1	—
Deferred revenues	39.1	36.7
Other	48.2	45.3
Total deferred credits and other liabilities	2,158.8	2,091.7
Total liabilities	5,679.9	5,269.1
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	999.6	969.2
Retained earnings	1,576.8	1,380.6
Accumulated other comprehensive loss, net of tax	(35.5)	(60.2)
Total OGE Energy stockholders' equity	2,540.9	2,289.6
Noncontrolling interests	158.0	110.4
Total stockholders' equity	2,698.9	2,400.0
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$8,378.8	$7,669.1

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

Table of Contents

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	Total
Balance at December 31, 2010	$1.0	$968.2	$1,380.6	$(60.2)	$110.4	$2,400.0
Comprehensive income (loss)						
Net income	—	—	306.5	—	13.9	320.4
Other comprehensive income (loss), net of tax	—	—	—	24.7	2.1	26.8
Comprehensive income (loss)	—	—	306.5	24.7	16.0	347.2
Dividends declared on common stock	—	—	(110.3)	—	—	(110.3)
Issuance of common stock	—	11.0	—	—	—	11.0
Stock-based compensation	—	1.5	—	—	—	1.5
Contributions from noncontrolling interest partners	—	29.1	—	—	44.4	73.5
Distributions to noncontrolling interest partners	—	—	—	—	(12.8)	(12.8)
Deferred income taxes attributable to contributions from noncontrolling interest partners	—	(11.2)	—	—	—	(11.2)
Balance at September 30, 2011	$1.0	$998.6	$1,576.8	$(35.5)	$158.0	$2,698.9
Balance at December 31, 2009	$1.0	$886.7	$1,227.8	$(74.7)	$20.0	$2,060.8
Comprehensive income (loss)						
Net income	—	—	264.6	—	2.0	266.6
Other comprehensive income (loss), net of tax	—	—	—	5.8	—	5.8
Comprehensive income (loss)	—	—	264.6	5.8	2.0	272.4
Dividends declared on common stock	—	—	(105.9)	—	—	(105.9)
Issuance of common stock	—	13.5	—	—	—	13.5
Stock-based compensation	—	7.5	—	—	—	7.5
Balance at September 30, 2010	$1.0	$907.7	$1,386.5	$(68.9)	$22.0	$2,248.3

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 September 30, 2011, the Company indirectly owns an 86.7 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 (see Note 3). The Company continues to consolidate Enogex Holdings in its consolidated financial statements as OGE Energy has a controlling financial interest over the operations of Enogex Holdings. Prior to November 1, 2010, OER, whose primary operations are in natural gas marketing, was directly owned by OGE Energy. On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Accordingly, the discussion that follows includes the results of OER in Enogex's results for all periods presented. Also, Enogex LLC holds a 50 percent ownership interest in Atoka. The Company has consolidated Atoka in its 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 September 30, 2011 and December 31, 2010, the results of its operations for the three and nine months ended September 30, 2011 and 2010 and the results of its cash flows for the nine months ended September 30, 2011 and 2010, have been included and are of a normal recurring nature except as otherwise disclosed.

Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011 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 2010 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

Table of Contents

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)	September 30, 2011	December 31, 2010
Regulatory Assets		
Current		
Fuel clause under recoveries	$33.2	$1.0
Other (A)	8.7	4.9
Total Current Regulatory Assets	$41.9	$5.9
Non-Current		
Benefit obligations regulatory asset	$274.0	$365.5
Income taxes recoverable from customers, net	51.8	43.3
Smart Grid	29.4	14.2
Deferred storm expenses	25.5	28.6
Unamortized loss on reacquired debt	14.5	15.3
Deferred Pension expenses	10.2	13.5
Red Rock deferred expenses	6.9	7.2
Other	3.0	1.8
Total Non-Current Regulatory Assets	$415.3	$489.4
Regulatory Liabilities		
Current		
Smart Grid rider over collections (B)	$23.5	$10.4
Fuel clause over recoveries	8.5	29.9
Other (B)	15.7	10.5
Total Current Regulatory Liabilities	$47.7	$50.8
Non-Current		
Accrued removal obligations, net	$204.5	$184.9
Pension tracker	18.7	8.2
Total Non-Current Regulatory Liabilities	$223.2	$193.1

(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 the Company 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, of which the financial effects could be significant.

2. Accounting Pronouncement

In September 2011, the Financial Accounting Standards Board issued "Intangibles - Goodwill and Other: Testing Goodwill for Impairment" which amends previous guidance in this area. The new standard provides an entity the option of first assessing qualitative factors (events and circumstances) to determine whether it is necessary to perform the current two-step impairment test. If an entity determines, as a result of its qualitative assessment, that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. An entity can choose to perform the qualitative assessment on none, some or all of its reporting units. Under the new standard, an entity can bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step impairment test, and then resume performing the qualitative assessment in any subsequent period. The new standard also will expand upon the examples of events and circumstances that an entity should consider between annual impairment tests in determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The new standard is applicable to all entities that have goodwill reported in their financial statements. The new standard is effective for interim and annual reporting period goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The

Table of Contents

Company plans to adopt this new standard effective January 1, 2012. The Company expects to record a significant amount of goodwill as part of the gas gathering acquisitions discussed in Note 17.

3. Noncontrolling Interest Owner

The following table summarizes changes in OGE Energy's equity attributable to changes in its ownership interest in Enogex Holdings during the nine months ended September 30, 2011. There were no contributions by OGE Energy or the ArcLight group to fund Enogex LLC's 2011 capital requirements during the three months ended September 30, 2011. Also, there were no sales of additional membership interests in Enogex Holdings to the ArcLight group during the three months ended September 30, 2011.

(In millions)	
Net income attributable to OGE Energy	$306.5
Transfers (to) from the noncontrolling interest	
Increase in paid-in capital for sale of 100,000 units of Enogex Holdings	0.9
Increase in paid-in capital for issuance of 4,303,007 units of Enogex Holdings	28.2
Decrease in paid-in capital for deferred income taxes attributable to the sale and issuance of units of Enogex Holdings	(11.2)
Net transfers from the noncontrolling interest	17.9
Change from net income attributable to OGE Energy and transfers from noncontrolling interest	$324.4

The following table summarizes changes in OGE Holdings' and the ArcLight group's membership interest in Enogex Holdings for the nine months ended September 30, 2011. Prior to November 1, 2010, Enogex Holdings was wholly owned by OGE Energy.

(In millions)	OGE Holdings	ArcLight group	Total
Balance at December 31, 2010 (units)	90.1	9.9	100.0
Ownership percentage at December 31, 2010	90.1 %	9.9 %	100.0 %
Sale of 100,000 units of Enogex Holdings (A)	(0.1)	0.1	—
Issuance of 4,303,007 units of Enogex Holdings (B)	0.4	3.9	4.3
Balance at September 30, 2011 (units)	90.4	13.9	104.3
Ownership percentage at September 30, 2011	86.7 %	13.3 %	100.0 %
Issuance of 5,405,406 units of Enogex Holdings (C)	0.5	4.9	5.4
Issuance of 5,725,190 units of Enogex Holdings (D)	2.9	2.8	5.7
Balance at November 1, 2011 (units)	93.8	21.6	115.4
Ownership percentage at November 1, 2011	81.3 %	18.7 %	100.0 %

(A) On February 1, 2011, OGE Energy sold a 0.1 percent membership interest in Enogex Holdings to the ArcLight group for $1.9 million.
(B) On February 1, 2011, OGE Energy and the ArcLight group made contributions of $8.0 million and $71.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements.
(C) On October 3, 2011, OGE Energy and the ArcLight group made contributions of $10.0 million and $90.0 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements.
(D) On November 1, 2011, OGE Energy and the ArcLight group made contributions of $53.0 million each to fund Enogex's gas gathering acquisitions as discussed in Note 17.

The following table summarizes the quarterly distributions by Enogex Holdings to its partners during the nine months ended September 30, 2011.

(In millions)	OGE Holdings Portion	ArcLight group's Portion	Total Distribution
First quarter 2011	$7.5	$0.8	$8.3
Second quarter 2011	34.3	5.3	39.6
Third quarter 2011	43.4	6.6	50.0
Total	$85.2	$12.7	$97.9

Table of Contents

4. Impairment of Assets

Atoka operates a 20 MMcf/d refrigeration processing plant which processes gas gathered in the Atoka area. The processing plant is leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to the Atoka plant and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. As a result, in August 2011 Enogex recorded a pre-tax impairment loss of $5.0 million in the Gathering and Processing segment associated with the cost it had capitalized in connection with the installation of the leased plant as it will not be able to recover the remaining value of the assets through future cash flows. The Atoka plant assets were measured at fair value on a nonrecurring basis and are considered level 3 in the fair value hierarchy (see Note 5). The noncontrolling interest portion of the pre-tax impairment loss is $2.5 million which is included in Net Income Attributable to Noncontrolling Interests in the Company's Condensed Consolidated Statement of Income.

5. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data are 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 option 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). Instruments classified as Level 3 include NGLs options and the revaluation of the Atoka plant assets (see Note 4).

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, NGLs options contracts are valued using internally developed methodologies that consider historical relationships among various commodities 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

Table of Contents

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 September 30, 2011 and December 31, 2010 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 September 30, 2011 and December 31, 2010.

September 30, 2011

(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	$35.1	$31.3	$—	$—
Significant other observable inputs (Level 2)	2.8	9.4	2.6	2.6
Significant unobservable inputs (Level 3)	1.5	—	—	—
Total fair value	39.4	40.7	2.6	2.6
Netting adjustments	(37.3)	(33.7)	—	—
Total	$2.1	$7.0	$2.6	$2.6

December 31, 2010

(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	$20.6	$20.2	$—	$—
Significant other observable inputs (Level 2)	2.7	30.7	2.5	2.8
Significant unobservable inputs (Level 3)	13.3	—	—	—
Total fair value	36.6	50.9	2.5	2.8
Netting adjustments	(34.4)	(34.1)	—	—
Total	$2.2	$16.8	$2.5	$2.8

(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 liabilities exclude fuel reserves for over retained fuel due to shippers of $3.0 million and $3.9 million at September 30, 2011 and December 31, 2010, 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 and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Commodity Contracts			
	Assets		Liabilities	
(In millions)	2011	2010	2011	2010
Balance at January 1	$13.3	$49.0	$—	$14.7
Total gains or losses				
Included in other comprehensive income	(4.8)	(3.9)	—	(5.1)
Settlements	(3.3)	(4.1)	—	(1.4)
Balance at March 31	5.2	41.0	—	8.2

Total gains or losses				
Included in other comprehensive income	(1.0)	7.2	—	(3.7)
Settlements	(1.7)	(6.1)	—	(2.7)
Balance at June 30	2.5	42.1	—	1.8
Total gains or losses				
Included in other comprehensive income	0.4	(8.5)	—	2.3
Settlements	(1.4)	(6.7)	—	(0.9)
Balance at September 30	$1.5	$26.9	$—	$3.2

Table of Contents

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 September 30, 2011 and December 31, 2010.

	September 30, 2011		December 31, 2010	
(In millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Derivative Contracts	$2.1	$2.1	$2.2	$2.2
Price Risk Management Liabilities				
Energy Derivative Contracts	$7.0	$7.0	$16.8	$16.8
Long-Term Debt				
OG&E Senior Notes	$1,903.8	$2,362.8	$1,655.0	$1,831.5
OGE Energy Senior Notes	99.6	109.7	99.7	106.4
OG&E Industrial Authority Bonds	135.4	135.4	135.4	135.4
Enogex LLC Senior Notes	448.1	502.7	447.8	480.7
Enogex LLC Revolving Credit Agreement	—	—	25.0	25.0

The carrying value of the financial instruments on the Condensed Consolidated Balance Sheets not otherwise discussed above 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.

6. 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 recognition is recorded 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 its 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.

Table of Contents

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 September 30, 2011 mature by the end of the first quarter of 2012.

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 September 30, 2011 and December 31, 2010, 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.

Table of Contents

Quantitative Disclosures Related to Derivative Instruments

At September 30, 2011, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	2011 Gross Notional Volume (A)
Enogex processing hedges	
NGLs sales	0.3
Natural gas purchases	1.3
Enogex marketing hedges	
Natural gas sales	1.9

(A) Natural gas in million British thermal units; NGLs in barrels.

At September 30, 2011, 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)	16.5	58.0
Fixed Swaps/Futures	48.6	47.3
Options	19.2	13.0
Basis Swaps	7.7	8.1

(A) Natural gas in million British thermal units.

(B) 85.5 percent of the natural gas contracts have durations of one year or less, 6.5 percent have durations of more than one year and less than two years and 8.0 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 September 30, 2011 are as follows:

Instrument	Balance Sheet Location	Fair Value	
		Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	$1.5	$—
Natural Gas			
Financial Futures/Swaps	Current PRM	—	8.0
	Other Current Assets	1.9	0.2
Total		$3.4	$8.2

Derivatives Not Designated as Hedging Instruments

Natural Gas			
Financial Futures/Swaps	Current PRM	$0.1	$0.1
	Other Current Assets	33.5	31.7
Physical Purchases/Sales	Current PRM	1.8	0.4
	Non-Current PRM	0.3	0.1
Financial Options	Other Current Assets	0.3	0.2
Total		$36.0	$32.5
Total Gross Derivatives (A)		$39.4	$40.7

(A) See Note 5 for a reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at September 30, 2011.

15

Table of Contents

The fair value of the derivative instruments that are presented in the Company's Condensed Consolidated Balance Sheet at December 31, 2010 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	$13.3	$—
Natural Gas			
Financial Futures/Swaps	Current PRM	—	28.8
	Other Current Assets	0.6	0.3
Total		$13.9	$29.1
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$—	$0.1
	Other Current Assets	20.0	19.8
Physical Purchases/Sales	Current PRM	1.4	1.2
	Non-Current PRM	0.8	—
Financial Options	Other Current Assets	0.5	0.7
Total		$22.7	$21.8
Total Gross Derivatives (A)		$36.6	$50.9

(A) See Note 5 for a reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at December 31, 2010.

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 September 30, 2011.

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
NGLs Financial Options	$0.2	$(2.6)	$—
Natural Gas Financial Futures/Swaps	0.2	(7.5)	—
Total	$0.4	$(10.1)	$—

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2011 that is expected to be reclassified into income within the next 12 months is a loss of $8.4 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income

Natural Gas Physical Purchases/Sales	$(2.2)
Natural Gas Financial Futures/Swaps	0.2
Total	$(2.0)

Table of Contents

The following tables present the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended September 30, 2010.

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	$(12.2)	$1.5	$—
NGLs Financial Futures/Swaps	(1.2)	(0.3)	—
Natural Gas Financial Futures/Swaps	(5.5)	(6.7)	—
Total	$(18.9)	$(5.5)	$—

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(2.3)
Natural Gas Financial Futures/Swaps	0.6
Total	$(1.7)

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

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
NGLs Financial Options	$(9.0)	$(8.3)	$—
Natural Gas Financial Futures/Swaps	—	(22.2)	—
Total	$(9.0)	$(30.5)	$—

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2011 that is expected to be reclassified into income within the next 12 months is a loss of $8.4 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(7.1)
Natural Gas Financial Futures/Swaps	(0.2)
Total	$(7.3)

Table of Contents

The following tables present the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the nine months ended September 30, 2010.

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	$(1.2)	$2.0	$—
NGLs Financial Futures/Swaps	2.1	(2.2)	—
Natural Gas Financial Futures/Swaps	(15.4)	(18.7)	0.1
Total	$(14.5)	$(18.9)	$0.1

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(6.4)
Natural Gas Financial Futures/Swaps	0.8
Total	$(5.6)

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 nine months ended September 30, 2011 and 2010, 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 nine months ended September 30, 2011 and 2010, 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 September 30, 2011, the Company would have been required to post $6.1 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 September 30, 2011. 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.

7. Stock-Based Compensation

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the three and nine months ended September 30, 2011 and 2010 related to the Company's performance units and restricted stock.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Performance units				
Total shareholder return	$1.9	$1.5	$5.6	$4.7
Earnings per share	0.8	1.0	3.7	1.8
Total performance units	2.7	2.5	9.3	6.5

Restricted stock	0.2	0.3	0.7	0.7
Total compensation expense	$2.9	$2.8	$10.0	$7.2
Income tax benefit	$1.1	$1.1	$3.9	$2.8

Table of Contents

The following table summarizes the activity of the Company's stock-based compensation during the three months ended September 30, 2011.

	Shares	Fair Value
Grants		
Restricted stock	14,218	$49.24

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. During the three and nine months ended September 30, 2011, there were 14,718 shares and 284,423 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants and payouts of earned performance units. During the three and nine months ended September 30, 2011, there were 1,150 shares and 3,810 shares, respectively, of restricted stock returned to the Company to satisfy tax liabilities. The Company received less than $0.1 million and $0.8 million, respectively, during the three and nine months ended September 30, 2011 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 nine months ended September 30, 2011 due to the Company being in a tax net operating loss position in 2011.

8. Accumulated Other Comprehensive Income (Loss)

The following table summarizes the components of accumulated other comprehensive loss at September 30, 2011 and December 31, 2010 attributable to OGE Energy. At both September 30, 2011 and December 31, 2010, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

	September 30,	December 31,
(In millions)	2011	2010
Pension Plan and Restoration of Retirement Income Plan:		
Net loss	$(29.4)	$(31.1)
Prior service cost	(0.2)	(0.5)
Postretirement plans:		
Net loss	(12.3)	(13.6)
Prior service cost	9.3	—
Net transition obligation	(0.2)	(0.3)
Deferred commodity contracts hedging losses	(5.6)	(19.5)
Deferred interest rate swaps hedging losses	(0.8)	(1.0)
Total accumulated other comprehensive loss	(39.2)	(66.0)
Less: Accumulated other comprehensive loss attributable to noncontrolling interests	(3.7)	(5.8)
Accumulated other comprehensive loss, net of tax	$(35.5)	$(60.2)

9. 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. The Company 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.

10. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 69,986 shares and 215,832 shares, respectively, of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan during the three and nine months ended September 30, 2011 and received proceeds of $3.4 million and $10.6 million, respectively, during the three and nine months ended September 30, 2011. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan to fund capital

Table of Contents

requirements or working capital needs. At September 30, 2011, there were 2,430,456 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 September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Net Income Attributable to OGE Energy	$178.7	$163.1	$306.5	$264.6
Average Common Shares Outstanding				
Basic average common shares outstanding	98.0	97.4	97.9	97.3
Effect of dilutive securities:				
Contingently issuable shares (performance units)	1.3	1.6	1.3	1.5
Diluted average common shares outstanding	99.3	99.0	99.2	98.8
Basic Earnings Per Average Common Share				
Attributable to OGE Energy Common Shareholders	$1.82	$1.67	$3.13	$2.72
Diluted Earnings Per Average Common Share				
Attributable to OGE Energy Common Shareholders	$1.80	$1.65	$3.09	$2.68
Anti-dilutive shares excluded from earnings per share calculation	—	—	—	—

11. Long-Term Debt

At September 30, 2011, 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% - 0.44%	Garfield Industrial Authority, January 1, 2025	$47.0
0.20% - 0.44%	Muskogee Industrial Authority, January 1, 2025	32.4
0.29% - 0.50%	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.

Table of Contents

12. 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 $289.0 million and $145.0 million at September 30, 2011 and December 31, 2010, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at September 30, 2011.

Revolving Credit Agreements and Available Cash

Entity	Aggregate Commitment (In millions)	Amount Outstanding (A)	Weighted-Average Interest Rate		Maturity
OGE Energy (B)	$596.0	$289.0	0.36	% (D)	December 6, 2012
OG&E (C)	389.0	2.2	0.14	% (D)	December 6, 2012
Enogex LLC (E)	250.0	—	—	% (D)	March 31, 2013
	1,235.0	291.2	0.35	%	
Cash	5.6	N/A	N/A		N/A
Total	$1,240.6	$291.2	0.35	%	

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at September 30, 2011.

(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 September 30, 2011, there was $289.0 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 September 30, 2011, there was $2.2 million supporting letters of credit.

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

(E) This bank facility is available to provide revolving credit borrowings for Enogex LLC. As Enogex LLC's credit agreement matures on March 31, 2013, 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.

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.

13. 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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011 (A)	2010 (A)	2011 (B)	2010 (B)
Service cost	$4.4	$4.1	$13.2	$12.5
Interest cost	8.4	8.0	25.0	23.9
Expected return on plan assets	(11.4)	(10.6)	(34.1)	(31.8)
Amortization of net loss	4.8	5.3	14.4	15.9
Amortization of unrecognized prior service cost	0.6	0.6	1.8	1.8
Net periodic benefit cost	$6.8	$7.4	$20.3	$22.3

Table of Contents

	Restoration of Retirement Income Plan			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011 (A)	2010 (A)	2011 (B)	2010 (B)
Service cost	$0.3	$0.3	$0.8	$0.7
Interest cost	0.1	0.2	0.4	0.4
Amortization of net loss	0.1	—	0.3	0.2
Amortization of unrecognized prior service cost	0.1	0.1	0.5	0.5
Net periodic benefit cost	$0.6	$0.6	$2.0	$1.8

(A) In addition to the $7.4 million and $8.0 million of net periodic benefit cost recognized during the three months ended September 30, 2011 and 2010, respectively, OG&E recognized an increase in pension expense during the three months ended September 30, 2011 and 2010 of $2.7 million and $2.3 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).

(B) In addition to the $22.3 million and $24.1 million of net periodic benefit cost recognized during the nine months ended September 30, 2011 and 2010, respectively, OG&E recognized an increase in pension expense during the nine months ended September 30, 2011 and 2010 of $8.0 million and $5.8 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 September 30,		Nine Months Ended September 30,	
(In millions)	2011 (C)	2010	2011 (C)	2010
Service cost	$0.8	$1.1	$2.6	$3.2
Interest cost	3.2	4.2	9.4	12.7
Expected return on plan assets	(1.2)	(1.7)	(3.8)	(5.2)
Amortization of transition obligation	0.7	0.7	2.1	2.1
Amortization of net loss	4.6	3.0	13.7	9.1
Amortization of unrecognized prior service cost	(4.2)	—	(12.4)	—
Net periodic benefit cost	$3.9	$7.3	$11.6	$21.9

(C) In addition to the $3.9 million and $11.6 million of net periodic benefit cost recognized during the three and nine months ended September 30, 2011, respectively, OG&E recognized an increase in postretirement medical expense during the three and nine months ended September 30, 2011 of $0.8 million and $2.5 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).

Pension Plan Funding

In the third quarter of 2011, the Company contributed $10 million to its Pension Plan for a total contribution of $50 million to its Pension Plan during 2011. No additional contributions are expected in 2011.

14. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes. These segments are 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 for the three and nine months ended September 30, 2011 and 2010.

Table of Contents

Three Months Ended September 30, 2011 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$774.8	$103.7	$304.9	$160.0	$—	$(131.3)	$1,212.1
Cost of goods sold	334.7	58.6	233.2	163.1	—	(131.1)	658.5
Gross margin on revenues	440.1	45.1	71.7	(3.1)	—	(0.2)	553.6
Other operation and maintenance	108.3	13.7	28.8	1.8	(4.4)	(0.8)	147.4
Depreciation and amortization	54.9	5.2	13.4	—	3.6	—	77.1
Impairment of assets	—	—	5.0	—	—	—	5.0
Taxes other than income	18.2	3.5	1.8	0.1	0.8	—	24.4
Operating income (loss)	$258.7	$22.7	$22.7	$(5.0)	$—	$0.6	$299.7
Total assets	$6,451.8	$2,474.1	$1,189.1	$67.7	$3,149.8	$(4,953.7)	$8,378.8

Three Months Ended September 30, 2010 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$723.0	$103.5	$243.1	$206.5	$—	$(150.7)	$1,125.4
Cost of goods sold	311.2	64.8	178.9	207.6	—	(149.9)	612.6
Gross margin on revenues	411.8	38.7	64.2	(1.1)	—	(0.8)	512.8
Other operation and maintenance	110.8	11.6	22.0	1.8	(3.2)	(0.6)	142.4
Depreciation and amortization	53.1	5.2	12.6	—	2.8	—	73.7
Taxes other than income	16.9	3.3	1.4	0.1	0.8	—	22.5
Operating income (loss)	$231.0	$18.6	$28.2	$(3.0)	$(0.4)	$(0.2)	$274.2
Total assets	$5,882.7	$1,670.0	$941.1	$105.4	$2,834.4	$(3,906.2)	$7,527.4

Nine Months Ended September 30, 2011 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$1,765.6	$311.9	$860.7	$526.4	$—	$(433.9)	$3,030.7
Cost of goods sold	808.4	192.1	640.4	532.8	—	(431.9)	1,741.8
Gross margin on revenues	957.2	119.8	220.3	(6.4)	—	(2.0)	1,288.9
Other operation and maintenance	324.3	35.8	81.9	5.9	(13.3)	(2.3)	432.3
Depreciation and amortization	158.8	16.4	40.4	—	10.2	—	225.8
Impairment of assets	—	—	5.0	—	—	—	5.0
Taxes other than income	56.1	11.1	5.3	0.3	3.2	—	76.0
Operating income (loss)	$418.0	$56.5	$87.7	$(12.6)	$(0.1)	$0.3	$549.8
Total assets	$6,451.8	$2,474.1	$1,189.1	$67.7	$3,149.8	$(4,953.7)	$8,378.8

Nine Months Ended September 30, 2010 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$1,679.8	$311.7	$726.4	$641.2	$—	$(470.7)	$2,888.4
Cost of goods sold	792.8	191.9	527.5	644.8	—	(467.8)	1,689.2
Gross margin on revenues	887.0	119.8	198.9	(3.6)	—	(2.9)	1,199.2
Other operation and maintenance	305.9	35.2	66.8	6.6	(10.8)	(2.7)	401.0
Depreciation and amortization	153.4	16.0	37.5	—	8.3	—	215.2
Taxes other than income	51.8	10.6	4.9	0.3	2.9	—	70.5
Operating income (loss)	$375.9	$58.0	$89.7	$(10.5)	$(0.4)	$(0.2)	$512.5

Total assets	$5,882.7	$1,670.0	$941.1	$105.4	$2,834.4	$(3,906.2)	$7,527.4

23

Table of Contents

15. Commitments and Contingencies

Except as set forth below and in Note 16, the circumstances set forth in Notes 14 and 15 to the Company's Consolidated Financial Statements included in the Company's 2010 Form 10-K appropriately represent, in all material respects, the current status of the Company's material commitments and contingent liabilities.

Operating Lease Obligations

Enogex currently occupies 116,184 square feet of office space at its executive offices under a lease that expires March 31, 2012. On June 30, 2011, Enogex executed a five-year lease agreement for its executive offices that expires March 31, 2017. The lease payments are $9.9 million over the lease term which begins April 1, 2012.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,392 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 February 10, 2009, OG&E executed a short-term lease agreement for 270 railcars in accordance with new coal transportation contracts with BNSF Railway and Union Pacific. These railcars were needed to replace railcars that have been taken out of service or destroyed. The lease agreement expired with respect to 135 railcars on November 2, 2009 and was not replaced. The lease agreement with respect to the remaining 135 railcars expired on March 5, 2010 and was subsequently terminated.

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 Power Purchase Commitment

As previously disclosed, OG&E received approval on January 5, 2010 from the OCC for a wind power purchase agreement with a wind developer who was to build a new 130 megawatt wind farm in Dewey County near Taloga in northwestern Oklahoma. This wind farm went in service during July 2011. The agreement is a 20-year power purchase agreement, under which the developer will own and operate the wind generating facility and OG&E will purchase its electric output.

Farris Buser Litigation

On July 22, 2005, Enogex, along with certain other unaffiliated co-defendants, was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including Enogex and its subsidiaries, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages, plus attorneys' fees and costs, and punitive damages. Enogex and its subsidiaries filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Company filed a cross claim against Products seeking indemnification and/or contribution from Products based upon the 1997 sale of a third-party interest in one of Products natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex filed an answer to the amended petition and BP America, Inc. and BP America Production Company's cross claim on January 16, 2007. On October 14, 2011, this case was dismissed without prejudice. While this lawsuit could be re-filed, Enogex considers the claims and cross claim associated with this lawsuit to be without merit, based upon Enogex's investigation to date. Enogex now considers this case closed.

Table of Contents

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, claims made by third parties, environmental actions or the action of various regulatory 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. Except as otherwise stated above, in Note 16 below, in Item 1 of Part II of this Form 10-Q, in Notes 14 and 15 of Notes to Consolidated Financial Statements and Item 3 of Part I of the Company's 2010 Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

16. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 15 to the Company's Consolidated Financial Statements included in the Company's 2010 Form 10-K appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

OG&E Wholesale Agreement

On May 28, 2009, OG&E sent a termination notice to the Arkansas Valley Electric Cooperative that OG&E would terminate its wholesale power agreement to all points of delivery where OG&E sells or has sold power to the Arkansas Valley Electric Cooperative, effective November 30, 2011. In December 2010, OG&E and the Arkansas Valley Electric Cooperative entered into a new wholesale power agreement whereby OG&E will supply wholesale power to the Arkansas Valley Electric Cooperative through June 2015. On January 3, 2011, OG&E submitted this agreement to the FERC for approval. The FERC approved the new wholesale power agreement on March 2, 2011 and the new contract was effective May 1, 2011. The Arkansas Valley Electric Cooperative contract contributed $17.4 million, or 1.5 percent, to OG&E's gross margin for the year ended December 31, 2010.

OG&E Long-Term Gas Supply Agreements

In May 2010, the OCC approved OG&E's request for a waiver of the competitive bid rules to allow OG&E to negotiate desired long-term gas purchase agreements. On June 29, 2010, OG&E filed a separate application with the OCC seeking approval of four long-term gas purchase agreements, which would provide a 12-year supply of natural gas to OG&E and account for 25 percent of its currently projected natural gas fuel supply needs over the same time period. On September 26, 2010, OG&E filed a motion with the OCC to dismiss this case. On July 5, 2011, OG&E received an order from the OCC dismissing the case without prejudice.

OG&E Crossroads Wind Project

As previously disclosed, on July 29, 2010, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct Crossroads, with the rider being implemented as the individual turbines are placed in service. The wind turbines started being placed in service in September 2011. As part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for Crossroads which will allow Crossroads to interconnect at the anticipated 227.5 megawatts.

OG&E 2010 Arkansas Rate Case Filing

On September 28, 2010, OG&E filed a rate case with the APSC requesting a rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines, that have been completed since the last rate filing in August 2008, as well as increased operating costs. OG&E also sought recovery, through a rider, of the Arkansas jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. On June 17, 2011, the APSC approved a settlement agreement among all parties to the case and OG&E implemented new electric rates effective June 20, 2011. Key items of the APSC order include: (i) the recovery of and a return on significant electric system expansions and upgrades, including high-voltage transmission lines, as well as increased operating costs, totaling $8.8 million annually; (ii)

Table of Contents

authorization for OG&E to recover the actual cost of third-party transmission charges and SPP administrative fees through a rider mechanism which will remain in effect until new rates are implemented after OG&E's next general rate case (the Arkansas jurisdictional portion of the combined costs is expected to be $1.0 million in 2011); and (iii) the deferral of certain expenses associated with a customer education program in an amount not to exceed $0.3 million per year for a maximum of two years.

OG&E SPP Cost Tracker

On October 7, 2010, OG&E filed an application with the OCC seeking recovery of the Oklahoma jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. OG&E requested authorization to implement a cost tracker in order to recover from its retail customers the third-party project costs discussed above and to collect its administrative SPP cost assessment levied under Schedule 1A of the SPP open access transmission tariff, which is currently recovered in base rates. OG&E also requested authorization to establish a regulatory asset effective January 1, 2011 in order to give OG&E the opportunity to recover such costs that will be paid but not recovered until the cost tracker is made effective. On February 8, 2011, all parties signed a settlement agreement in this matter which would allow OG&E to recover the costs discussed in (i) above through a recovery rider effective January 1, 2011. OG&E anticipates recovering $1.8 million of incremental revenues in 2011 through the rider. Rather than including the costs of the SPP administrative fee assessment in the recovery rider, the stipulating parties agreed to allow OG&E to include the projected 2012 level of the SPP administrative fee assessment in its next Oklahoma rate case which was filed in July 2011. The settlement agreement also stated that in OG&E's 2011 Oklahoma general rate case filing, OG&E would propose that recovery in base rates for the costs of transmission projects it constructs and owns and that are authorized by the SPP in its regional planning processes should be limited to the Oklahoma retail jurisdictional share of the costs for such projects allocated to OG&E by the SPP. On March 28, 2011, the OCC issued an order in this matter approving the settlement agreement.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2009

On October 29, 2010, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2009 fuel adjustment clause. On December 28, 2010, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. An intervenor representing a group of OG&E's industrial customers filed testimony on March 11, 2011 seeking a $15.5 million refund related to (i) a purported failure by OG&E to maximize the use of its coal-fired power plants and (ii) an inappropriate extension of the existing gas transportation and storage contract between OG&E and Enogex. OG&E filed rebuttal testimony on April 4, 2011 in opposition to the claims of the intervenor. On August 11, 2011, all parties to this case signed a settlement agreement in this matter, stating that (i) OG&E was prudent in its operations during 2009; (ii) a third party expert should be hired to evaluate OG&E's future gas transportation and storage needs and that OG&E should file a plan for meeting its future gas transportation and storage needs by mid-2012; and (iii) with respect to the existing gas transportation and storage contract with Enogex, OG&E will return $8.4 million to its customers in settlement for all periods under the contract through April 30, 2013. In August 2011, OG&E credited $4.9 million to its customers and will credit the remaining amount on a monthly basis through April 30, 2013. The OCC issued an order approving the settlement agreement on August 29, 2011.

OG&E Smart Grid Project

As previously reported in the Company's 2010 Form 10-K, on December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant awarded by the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009. On June 22, 2011, OG&E reached a settlement agreement with all the parties in this matter. OG&E and the other parties in this matter agreed to ask the APSC to approve the settlement agreement including the following: (i) pre-approval of system-wide deployment of smart grid technology in Arkansas and authorization for OG&E to begin recovering the prudently incurred costs of the Arkansas system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement; (ii) cost recovery through the rider would commence when all of the smart meters to be deployed in Arkansas are in service; (iii) OG&E guarantees that customers will receive certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider; and (iv) the stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning after an order is issued in OG&E's next general rate case. OG&E currently expects to spend $14 million, net of funds from the U.S. Department of Energy grant, in capital expenditures to implement smart grid in Arkansas pursuant to the settlement agreement. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement.

Table of Contents

OG&E FERC Transmission Rate Incentive Filing

On February 18, 2011, OG&E submitted to the FERC a request seeking limited transmission rate incentives for five transmission projects. This February 18, 2011 request is in addition to the October 12, 2010 request described in the Company's 2010 Form 10-K. OG&E requested recovery of 100 percent of all prudently incurred construction work in progress in rate base for five 345 kilovolt Extra High Voltage transmission projects to be constructed and owned by OG&E within the SPP's region. OG&E also requested to recover 100 percent of all prudently incurred development and construction costs if the transmission projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. On April 19, 2011, the FERC granted these incentives for the Sooner-Rose Hill, Sunnyside-Hugo and Balanced Portfolio 3E transmission projects discussed in Note 15 of the Company's 2010 Form 10-K.

OG&E Pension Tracker Modification Filing

On February 22, 2011, OG&E filed an application with the OCC requesting that OG&E's pension tracker be modified to include the difference between the level of retiree medical costs authorized in OG&E's last rate case and the current level of these expenses as a regulatory liability, effective January 1, 2011. On June 23, 2011, a settlement agreement was filed by parties in the case stating that the pension tracker should be modified as proposed by OG&E and that the level of retiree medical costs included in base rates will be reviewed and determined in OG&E's next rate case. On September 27, 2011, the OCC issued an order in this matter approving the settlement agreement.

OG&E Demand and Energy Efficiency Program Filing

To build on the success of its earlier programs and further promote energy efficiency and conservation for each class of OG&E customers, on March 15, 2011, OG&E filed an application with the APSC seeking approval of several programs, ranging from residential weatherization to commercial lighting. In seeking approval of these programs, OG&E also sought recovery of the program and related costs through a rider that would be added to customers' electric bills. On June 30, 2011, the APSC issued an order approving OG&E's energy efficiency plan for 2011 and approving OG&E's energy efficiency cost recovery rider for 2011. In Arkansas, OG&E's program is expected to cost $7.0 million over a three-year period and is expected to increase the average residential electric bill by $1.47 per month.

FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid in a particular region, along with the corresponding process for allocating the costs of such expansions. The revised regulations apply only to "new transmission facilities," which are described as those subject to evaluation or reevaluation (under the applicable local or regional transmission planning process) subsequent to the effective date of the regulatory compliance filings required by the rule, which are expected to be filed during the third quarter of 2012. Order No. 1000 leaves to individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

The new rule requires, among other things, public utility transmission providers, such as the SPP, to participate in a process that produces a regional transmission plan satisfying certain standards, and requires that each such regional process consider transmission needs driven by public policy requirements (such as state or Federal policies favoring increased use of renewable energy resources). Order No. 1000 also directs public utility transmission providers to coordinate with neighboring transmission planning regions. In addition, the final rule establishes specific regional cost allocation principles and directs public utility transmission providers to participate in regional and interregional transmission planning processes that satisfy these principles.

On the issue of determining how entities are to be selected to develop and construct the specific transmission projects, Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariffs and agreements provisions that establish any federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, the final rule is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities, and Order No. 1000 does not alter an incumbent transmission owner's use and control of existing rights of way. The final rule also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP currently has a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build various transmission projects in Oklahoma.

The Company is continuing to evaluate Order No. 1000 and cannot at this time determine its precise impact on OG&E. Nevertheless, at the present time, the Company has no reason to believe that the implementation of Order No. 1000 will impact

Table of Contents

OG&E's transmission projects currently under development and construction for which OG&E has received a notice to proceed from the SPP.

Enogex FERC Section 311 2007 Rate Case

On October 1, 2007, Enogex made its required triennial rate filing at the FERC to update its Section 311 maximum interruptible transportation rates for Section 311 service in the East Zone and West Zone. Enogex's filing requested an increase in the maximum zonal rates and proposed to place such rates into effect on January 1, 2008. A number of parties intervened and some also filed protests. Enogex did not place the increased rates set forth in its October 2007 rate filing into effect but rather continued to provide interruptible Section 311 service under the maximum Section 311 rates for both zones approved by the FERC in the previous rate case. A final settlement was filed with the FERC on August 5, 2010. With the filing of Enogex's Section 311 2009 rate case discussed below, the rate period for the 2007 rate case became a limited locked-in period from January 2008 through May 2009. On October 13, 2011, the FERC issued an order in this matter approving the settlement agreement, providing that Enogex's rates from its previous rate case remain in effect and that rate treatment for the MEP lease agreement discussed below will be addressed in Enogex's Section 311 2009 rate case.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex 2007 rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to MEP and with separate applications filed by MEP with the FERC for a certificate to construct and operate the MEP pipeline and to lease firm capacity from Enogex. Enogex and MEP separately opposed this intervenor's protests and assertions in its initial and subsequent pleadings. On July 25, 2008, the FERC issued an order (i) approving the MEP project including the approval of a limited jurisdiction certificate and (ii) authorizing the Enogex lease agreement with MEP. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, a protestor sought rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. On December 28, 2010, the Court of Appeals issued an opinion generally upholding the FERC's orders, but remanding the case for further explanation of one aspect of the FERC's reasoning. The Court of Appeals emphasized that it was not vacating the FERC's orders and that its approval of the Enogex lease agreement with MEP remains in effect and legally binding. On remand, the FERC must clarify that its decision was based on a finding that the lease does not adversely affect existing customers on Enogex's system. On January 21, 2011, Apache Corporation filed a motion asking the FERC to establish procedures on remand and to either condition the lease on Enogex's willingness to provide firm Section 311 transportation service to existing customers on all portions of its system or to establish an expedited briefing schedule. On February 7, 2011, Enogex, MEP and Chesapeake Energy Corporation filed a joint answer asking the FERC to find, among other things, that the reduction in the amount of interruptible transportation capacity available due to the MEP lease did not have an adverse affect on Apache Corporation and to acknowledge that Apache Corporation's request to condition the lease on the provision of West Zone 311 firm transportation service has been addressed as Enogex filed a rate case on January 28, 2011 proposing to implement such service effective March 1, 2011. On March 1, 2011, Apache Corporation filed an answer seeking to refute some of the arguments presented in the joint answer filed by Enogex, MEP and Chesapeake Energy Corporation. On March 3, 2011, the FERC issued an order on remand affirming the authorizations previously granted to Enogex and MEP and clarifying the legal standard applied in response to the court's directive. On April 4, 2011, Apache Corporation filed a request for rehearing of the FERC's order on remand. On September 29, 2011, the FERC issued an order denying Apache Corporation's motion for rehearing. Apache Corporation has until November 28, 2011 to appeal the FERC's March 3, 2011 order on remand and/or the September 29, 2011 order denying rehearing. In accordance with the settlement agreement discussed above, rate treatment for the MEP lease agreement will be addressed in Enogex's Section 311 2009 rate case.

Pending Regulatory Matters

OG&E 2011 Oklahoma Rate Case Filing

As part of the Joint Stipulation and Settlement Agreement reached in OG&E's 2009 Oklahoma rate case filing, the parties agreed that OG&E would file a rate case on or before June 30, 2011. On May 27, 2011, OG&E requested an extension until the end of July 2011 for filing the Oklahoma rate case. 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 is requesting a return on equity of 11.00 percent based on a common equity percentage of 53 percent. Each 0.10 percent change in the requested return on equity affects the requested rate increase by $3.0 million. In its application, OG&E seeks to recover 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. A hearing in this matter is scheduled for December 13, 2011. OG&E expects to receive an order from the OCC in early 2012.

Table of Contents

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2010

On August 19, 2011, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2010 fuel adjustment clause. On October 18, 2011, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. A procedural schedule has not yet been established in this matter.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the Statement of Operating Conditions filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service are being collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the Statement of Operating Conditions filing and some additionally filed protests. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. On October 4, 2011, Enogex filed a settlement agreement with the FERC. All parties have agreed to support or not oppose settlement of the rate case and the proposed revisions to the Statement of Operating Conditions. 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 cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. At Enogex's request, the protest deadline was extended to November 28, 2011. The regulations provide that the FERC has 150 days to act on the filing but also permit the FERC to issue an order extending the time period for action.

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 Zone for the upcoming 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 on Enogex's filing was March 15, 2011, and no protests were filed. A FERC order is pending.

17. Subsequent Event

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream pursuant to which Enogex agreed to acquire 100 percent of the membership interest in

Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and an agreement with Cordillera pursuant to which Cordillera agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group (as discussed in Note 3) as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011. The Company has not completed the appraisal and purchase price allocation for this transaction but expects to record a significant amount of goodwill and intangible assets as part of this transaction in the Gathering and Processing segment. All of the goodwill is expected to be deductible for tax purposes. Certain of the required accounting disclosures related to this transaction have been excluded from this Form 10-Q because it is impracticable to provide such disclosures when certain information is not yet available.

Table of Contents

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 September 30, 2011, the Company indirectly owns an 86.7 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC. As a result of contributions made by OGE Energy and the ArcLight group subsequent to September 30, 2011, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings at November 1, 2011 (see Notes 3 and 17 of Notes to Condensed Consolidated Financial Statements). Prior to November 1, 2010, OER, whose primary operations are in natural gas marketing, was directly owned by OGE Energy. On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Accordingly, the discussion that follows includes the results of OER in Enogex's results for all periods presented.

Overview

Financial 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 intends to execute its vision by focusing on its regulated electric utility business and unregulated natural gas midstream business. The Company intends to maintain the majority of its assets in the regulated utility business, however, the Company anticipates significant growth opportunities for its natural gas midstream business. With respect to its natural gas midstream business, the Company intends to focus on growing products and services with limited or manageable commodity price exposure and intends to seek to mitigate exposure to fluctuations in commodity prices by continuing to increase the percentage that fee-based processing agreements represent of the total processing volumes. 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 target payout ratio for the Company is to pay out as 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 September 30, 2011 as Compared to Three Months Ended September 30, 2010

Net income attributable to OGE Energy was $178.7 million, or $1.80 per diluted share, during the three months ended September 30, 2011, as compared to $163.1 million, or $1.65 per diluted share, during the same period in 2010. The increase in net income attributable to OGE Energy of $15.6 million, or 9.6 percent, or $0.15 per diluted share, during the three months ended September 30, 2011 as compared to the same period in 2010 was primarily due to:

- an increase in net income at OG&E of $16.5 million, or 11.6 percent, or $0.17 per diluted share of the Company's

Table of Contents

common stock, primarily due to a higher gross margin primarily from warmer weather in OG&E's service territory partially offset by higher income tax expense;

- a decrease in net income at Enogex of $3.5 million, or 15.4 percent, or $0.04 per diluted share of the Company's common stock, primarily due to higher operation and maintenance expense and the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by a higher gross margin primarily from increased gathered volumes associated with ongoing expansion projects, higher NGLs prices and higher average natural gas prices; and
- an increase in net income at OGE Energy of $2.6 million, or $0.02 per diluted share of the Company's common stock, primarily due to a higher income tax benefit.

Timing Item. Enogex's net income for the three months ended September 30, 2011 was $19.3 million, which included a loss of $1.3 million resulting from recording OER's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

Nine Months Ended September 30, 2011 as Compared to Nine Months Ended September 30, 2010

Net income attributable to OGE Energy was $306.5 million, or $3.09 per diluted share, during the nine months ended September 30, 2011, as compared to $264.6 million, or $2.68 per diluted share, during the same period in 2010. Included in net income attributable to OGE Energy during the nine months ended September 30, 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011). The increase in net income attributable to OGE Energy of $41.9 million, or 15.8 percent, or $0.41 per diluted share, during the nine months ended September 30, 2011 as compared to the same period in 2010 was primarily due to:

- an increase in net income at OG&E of $40.3 million, or 19.8 percent, or $0.40 per diluted share of the Company's common stock, primarily due to a higher gross margin primarily from warmer weather in OG&E's service territory partially offset by higher other operation and maintenance expense and higher income tax expense. Income tax expense was higher due to higher pre-tax income which more than offset the effects of the Medicare Part D subsidy discussed above;
- a decrease in net income at Enogex of $5.7 million, or 8.3 percent, or $0.06 per diluted share of the Company's common stock, primarily due to higher operation and maintenance expense and the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by a higher gross margin primarily from increased gathered volumes associated with ongoing expansion projects and higher NGLs prices, the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets, lower interest expense and lower income tax expense related to lower pre-tax income and the Medicare Part D subsidy discussed above; and
- an increase in net income at OGE Energy of $7.3 million, or 97.3 percent, or $0.07 per diluted share of the Company's common stock, primarily due to a higher income tax benefit related to the Medicare Part D subsidy discussed above.

Timing Item. Enogex's net income for the nine months ended September 30, 2011 was $63.1 million, which included a loss of $1.3 million resulting from recording OER's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

Recent Developments and Regulatory Matters

OG&E Crossroads Wind Project

As previously disclosed, on July 29, 2010, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct Crossroads, with the rider being implemented as the individual turbines are placed in service. The wind turbines started being placed in service in September 2011. As part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for Crossroads which will allow Crossroads to interconnect at the anticipated 227.5 megawatts.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2009

On October 29, 2010, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2009 fuel adjustment clause. On December 28, 2010, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. An intervenor representing a group of OG&E's industrial customers filed

Table of Contents

testimony on March 11, 2011 seeking a $15.5 million refund related to (i) a purported failure by OG&E to maximize the use of its coal-fired power plants and (ii) an inappropriate extension of the existing gas transportation and storage contract between OG&E and Enogex. OG&E filed rebuttal testimony on April 4, 2011 in opposition to the claims of the intervenor. On August 11, 2011, all parties to this case signed a settlement agreement in this matter, stating that (i) OG&E was prudent in its operations during 2009; (ii) a third party expert should be hired to evaluate OG&E's future gas transportation and storage needs and that OG&E should file a plan for meeting its future gas transportation and storage needs by mid-2012; and (iii) with respect to the existing gas transportation and storage contract with Enogex, OG&E will return $8.4 million to its customers in settlement for all periods under the contract through April 30, 2013. In August 2011, OG&E credited $4.9 million to its customers and will credit the remaining amount on a monthly basis through April 30, 2013. The OCC issued an order approving the settlement agreement on August 29, 2011.

OG&E Pension Tracker Modification Filing

On February 22, 2011, OG&E filed an application with the OCC requesting that OG&E's pension tracker be modified to include the difference between the level of retiree medical costs authorized in OG&E's last rate case and the current level of these expenses as a regulatory liability, effective January 1, 2011. On June 23, 2011, a settlement agreement was filed by parties in the case stating that the pension tracker should be modified as proposed by OG&E and that the level of retiree medical costs included in base rates will be reviewed and determined in OG&E's next rate case. On September 27, 2011, the OCC issued an order in this matter approving the settlement agreement.

Enogex Cox City Plant Fire

As previously reported, 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. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December 2010. 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 $30 million. While Enogex believes that the costs in excess of the $10 million deductible should be reimbursed by insurance, the matter is currently being negotiated with the insurance company and Enogex cannot predict the precise outcome of these negotiations or the timing associated with the recovery. In October 2011, Enogex received a partial insurance reimbursement of $5.0 million. Although Enogex may receive reimbursement of additional portions of the costs in 2011, it is possible that some amounts may not be received until 2012. Enogex will recognize insurance recoveries in earnings as the insurance claims are resolved.

Enogex Contract Conversion

On August 26, 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's gathering and processing volumes on the Oklahoma portion of Enogex's system. The effect of this new arrangement is that (i) the acreage dedicated by the customer to Enogex for gathering and processing in Oklahoma has been increased for an extended term and (ii) the processing arrangement has been converted from keep-whole to fixed fee. As of August 26, 2011, the new arrangement will result in the estimated percentage of Enogex's natural gas processed volumes that are on a fixed fee basis increasing from 28 percent (as previously reported in the Company's 2011 earnings guidance assumptions in the Company's 2010 Form 10-K) to 34 percent and the estimated portion of such volumes that are on a keep-whole basis decreasing from 31 percent (as previously reported in the Company's 2011 earnings guidance assumptions in the Company's 2010 Form 10-K) to 26 percent. As a result of this transaction and as part of the new agreements, Enogex recorded $3.1 million in Deferred Revenues on the Company's Condensed Consolidated Balance Sheet which will be amortized on a straight-line basis over the life of the agreements.

Enogex Western Oklahoma / Texas Panhandle Gathering and Processing System Expansions

Enogex expects to expand its 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 processing capacity of 120 MMcf/d is expected to be in service in the second quarter of 2012, and the additional processing capacity is expected to be in service by the end of the third quarter of 2012. The new plant will be supported by the installation of 9,400 horsepower of field compression. The capital expenditures associated with this project are expected to be $140 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 are planned to occur in phases, with the initial phase calling for the installation of 96,280 horsepower of low pressure compression and over 440 miles of gathering pipe across

Table of Contents

the area. This infrastructure is expected to be constructed throughout 2012 and 2013. The capital expenditures associated with these expansions projects are expected to be $382 million.

Enogex expects to install 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 the third quarter of 2013. The capital expenditures associated with this project are expected to be $136 million.

Gas Gathering Acquisitions

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and an agreement with Cordillera pursuant to which Cordillera agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group (as discussed in Note 3) as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011. The Company has not completed the appraisal and purchase price allocation for this transaction but expects to record a significant amount of goodwill and intangible assets as part of this transaction in the Gathering and Processing segment. All of the goodwill is expected to be deductible for tax purposes. The Company believes that the transactions will provide Enogex with key new opportunities in the Granite Wash area.

2011 Outlook

In the Company's Form 10-Q for the quarter ended June 30, 2011, the Company indicated that it expected that earnings for 2011 would exceed the previously disclosed earnings guidance of between $299 million to $318 million of net income, or $3.00 to $3.20 per average diluted share. The Company now expects that its earnings for 2011 will be between $338 million to $343 million of net income, or $3.40 to $3.45 per average diluted share. The increase in 2011 earnings guidance is primarily a result of higher expected earnings at OG&E due to extremely hot summer weather in its service territory. The revised earnings guidance is below.

	Earnings Guidance per 2010 Form 10-K		Revised Earnings Guidance per Q3 2011 Form 10-Q	
(In millions, except per share data)	Dollars	Diluted EPS	Dollars	Diluted EPS
OG&E	$209 - $219	$2.10 - $2.20	$249 - $254	$2.50 - $2.55
Enogex	$90 - $104	$0.90 - $1.05	$90 - $95	$0.90 - $0.95
Holding Company	($4) - ($2)	($0.04) - ($0.02)	($4) - ($2)	($0.04) - ($0.02)
Consolidated	$299 - $318	$3.00 - $3.20	$338 - $343	$3.40 - $3.45

Key assumptions for 2011 include:

OG&E

The Company projects OG&E to earn in 2011 between $249 million to $254 million, or $2.50 to $2.55 per average diluted share compared to previous earnings guidance of between $209 million to $219 million, or $2.10 to $2.20 per average diluted share. The key factors and assumptions include:

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on revenues of $1.180 billion to $1.185 billion, which represents an increase from $1.105 billion to $1.115 billion that was assumed in the previous guidance. The increase in the gross margin projection is primarily due to the following:
- Higher than normal weather experienced year-to-date has increased the expected gross margin, net of the impact of the guaranteed flat bill program, $49 million; and
- Higher expected transmission revenues primarily attributed to recovery of construction work in progress, which is expected to increase gross margin by $12 million.

Table of Contents

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.

Enogex

The Company projects Enogex to earn in 2011 between $90 million to $95 million, or $0.90 to $0.95 per average diluted share compared to previous earnings guidance of between $90 million to $104 million of net income, or $0.90 to $1.05 per average diluted share, net of noncontrolling interest. The key factors and assumptions include:

- Total Enogex anticipated gross margin of between $450 million to $465 million compared to previous guidance of $435 million to $460 million. The gross margin assumption includes:
- Transportation and storage gross margin contribution of between $155 million to $165 million compared to previous guidance of between $145 million to $155 million of which 80 percent is attributable to the transportation business. This increase in estimated gross margin is primarily due to higher demand revenues and new customer contracts on the transportation system;
- Gathering and processing gross margin contribution of between $305 million to $310 million compared to previous guidance of between $290 million to $305 million of which 60 percent is attributable to the processing business. The increase in expected gross margin is due to higher than previously estimated NGLs prices partially offset by lower than previously estimated processing volumes and changes in the contract mix to reduce the percentage of processing volumes on a keep-whole basis;
- Offsetting the higher gross margins is a projected increase in operating expenses resulting from the delay of the insurance proceeds from the Cox City plant outage; and
- ArcLight group will own 19 percent of Enogex Holdings by the end of 2011 compared to previous guidance of 17 percent of Enogex Holdings by the end of 2011.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the three and nine months ended September 30, 2011 as compared to the same periods in 2010 and the Company's consolidated financial position at September 30, 2011. Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011 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 September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2011	2010	2011	2010
Operating income	$299.7	$274.2	$549.8	$512.5
Net income attributable to OGE Energy	$178.7	$163.1	$306.5	$264.6
Basic average common shares outstanding	98.0	97.4	97.9	97.3
Diluted average common shares outstanding	99.3	99.0	99.2	98.8
Basic earnings per average common share attributable to OGE Energy common shareholders	$1.82	$1.67	$3.13	$2.72
Diluted earnings per average common share attributable to OGE Energy common shareholders	$1.80	$1.65	$3.09	$2.68
Dividends declared per common share	$0.3750	$0.3625	$1.1250	$1.0875

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.

Table of Contents

Operating Income (Loss) by Business Segment

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
OG&E (Electric Utility)	$258.7	$231.0	$418.0	$375.9
Enogex (Natural Gas Midstream Operations)				
Transportation and storage	22.7	18.6	56.5	58.0
Gathering and processing	22.7	28.2	87.7	89.7
Marketing (A)	(5.0)	(3.0)	(12.6)	(10.5)
Other Operations (B)	0.6	(0.6)	0.2	(0.6)
Consolidated operating income	$299.7	$274.2	$549.8	$512.5

(A) On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Accordingly, the results of OER are included in Enogex's results for all periods presented.

(B) 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.

Table of Contents

OG&E (Electric Utility)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	2011	2010	2011	2010
Operating revenues	$774.8	$723.0	$1,765.6	$1,679.8
Cost of goods sold	334.7	311.2	808.4	792.8
Gross margin on revenues	440.1	411.8	957.2	887.0
Other operation and maintenance	108.3	110.8	324.3	305.9
Depreciation and amortization	54.9	53.1	158.8	153.4
Taxes other than income	18.2	16.9	56.1	51.8
Operating income	258.7	231.0	418.0	375.9
Interest income	0.2	0.1	0.4	0.1
Allowance for equity funds used during construction	5.9	2.6	16.1	7.2
Other income (loss)	(3.1)	(1.1)	3.2	2.2
Other expense	3.4	0.4	4.9	1.4
Interest expense	28.8	27.4	82.2	76.8
Income tax expense	70.9	62.7	107.0	103.9
Net income	$158.6	$142.1	$243.6	$203.3
Operating revenues by classification				
Residential	$360.0	$330.9	$771.2	$729.8
Commercial	177.5	176.5	417.6	409.5
Industrial	68.2	66.2	168.2	164.5
Oilfield	49.8	49.6	127.4	125.6
Public authorities and street light	69.2	67.8	162.5	157.8
Sales for resale	22.8	19.3	50.9	50.5
Provision for rate refund	—	(0.4)	—	(0.4)
System sales revenues	747.5	709.9	1,697.8	1,637.3
Off-system sales revenues	13.6	5.8	35.5	19.7
Other	13.7	7.3	32.3	22.8
Total operating revenues	$774.8	$723.0	$1,765.6	$1,679.8
MWH (A) sales by classification (In millions)				
Residential	3.5	3.2	8.0	7.6
Commercial	2.0	1.9	5.3	5.1
Industrial	1.0	1.0	2.9	2.9
Oilfield	0.8	0.8	2.4	2.3
Public authorities and street light	0.9	0.9	2.4	2.3
Sales for resale	0.4	0.4	1.1	1.1
System sales	8.6	8.2	22.1	21.3
Off-system sales	0.4	0.2	1.0	0.5
Total sales	9.0	8.4	23.1	21.8
Number of customers	788,998	782,174	788,998	782,174
Average cost of energy per KWH (B) - cents				
Natural gas	4.319	4.546	4.388	4.838
Coal	2.077	1.951	2.048	1.891
Total fuel	3.155	3.084	2.963	3.063
Total fuel and purchased power	3.443	3.407	3.268	3.361
Degree days (C)				
Heating - Actual	17	7	2,095	2,305

Heating - Normal	29	29	2,228	2,228
Cooling - Actual	1,761	1,541	2,687	2,286
Cooling - Normal	1,295	1,295	1,850	1,850

(A) Megawatt-hour

(B) Kilowatt-hour

(C) 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.

Table of Contents

Three Months Ended September 30, 2011 as Compared to Three Months Ended September 30, 2010

Operating Income

OG&E's operating income increased $27.7 million, or 12.0 percent, during the three months ended September 30, 2011 as compared to the same period in 2010 primarily due to a higher gross margin.

Gross Margin

Gross margin was $440.1 million during the three months ended September 30, 2011 as compared to $411.8 million during the same period in 2010, an increase of $28.3 million, or 6.9 percent. The gross margin increased primarily due to:

- warmer weather in OG&E's service territory, which increased the gross margin by $10.2 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 $6.7 million;
- new customer growth in OG&E's service territory, which increased the gross margin by $5.7 million;
- revenues from the Arkansas rate increase, which increased the gross margin by $3.6 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $2.1 million; and
- higher revenues related to the renewal of the Arkansas Valley Electric Cooperative contract (see Note 16 of Notes to Condensed Consolidated Financial Statements), which increased the gross margin by $1.4 million.

These increases in gross margin were partially offset by a credit to customers related to the settlement of OG&E's 2009 fuel adjustment clause review (see Note 16 of Notes to Condensed Consolidated Financial Statements), which decreased the gross margin by $5.1 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $263.8 million during the three months ended September 30, 2011 as compared to $241.0 million during the same period in 2010, an increase of $22.8 million, or 9.5 percent, primarily due to higher natural gas and coal generation and higher coal 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 the Company and its customers. Purchased power costs were $69.2 million during the three months ended September 30, 2011 as compared to $69.8 million during the same period in 2010, a decrease of $0.6 million, or 0.9 percent, primarily due to a decrease in purchases in the energy imbalance service market partially offset by an increase in short-term power purchases and an increase in cogeneration costs.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses. 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 expenses were $108.3 million during the three months ended September 30, 2011 as compared to $110.8 million during the same period in 2010, a decrease of $2.5 million, or 2.3 percent. The decrease in other operation and maintenance expenses was primarily due to:

- a decrease of $3.5 million in employee benefits expense primarily due to a decrease in postretirement benefits expense related to amendments to the Company's retiree medical plan adopted in January 2011 (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011) partially offset by a modification to OG&E's pension tracker and a decrease in worker's compensation accruals during the three months ended September 30, 2011;
- a decrease of $2.9 million in injuries and damages expense primarily due to higher reserves on claims during the three months ended September 30, 2010;
- a decrease of $2.6 million related to more work being capitalized during the three months ended September 30, 2011;
- a decrease of $1.9 million related to decreased spending on vegetation management related to system hardening, which expenses are being recovered through a rider; and
- a decrease of $1.7 million in contract technical and construction services expense primarily attributable to

Table of Contents

increased spending for ongoing maintenance at some of OG&E's power plants during the three months ended September 30, 2010.

These decreases in other operation and maintenance expenses were partially offset by:

- an increase of $5.7 million in salaries and wages expense primarily due to salary increases in 2011, increased incentive compensation expense and increased overtime expense primarily due to storms in August 2011;
- an increase of $3.2 million in payroll and benefits expense and contract professional services allocated from the holding company; and
- a decrease of $1.0 million related to an adjustment during the three months ended September 30, 2011 to reclassify a portion of Smart Grid costs for the Arkansas jurisdiction to a regulatory asset.

Depreciation and amortization expense was $54.9 million during the three months ended September 30, 2011 as compared to $53.1 million during the same period in 2010, an increase of $1.8 million, or 3.4 percent, primarily due to additional assets placed into service during the second half of 2010 and 2011.
Taxes other than income were $18.2 million during the three months ended September 30, 2011 as compared to $16.9 million during the same period in 2010, an increase of $1.3 million, or 7.7 percent, primarily due to higher ad valorem taxes.
Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $5.9 million during the three months ended September 30, 2011 as compared to $2.6 million during the same period in 2010, an increase of $3.3 million primarily due to construction costs for Crossroads.

Other Income. Other income was a loss of $3.1 million during the three months ended September 30, 2011 as compared to a loss of $1.1 million during the same period in 2010, a decrease in other income of $2.0 million. The decrease in other income was primarily due to increased losses of $3.8 million recognized in the guaranteed flat bill program during the three months ended September 30, 2011 from higher than expected usage resulting from warmer weather partially offset by an increase of $2.1 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction.

Other Expense. Other expense was $3.4 million during the three months ended September 30, 2011 as compared to $0.4 million during the same period in 2010, an increase of $3.0 million, primarily due to an increase in charitable contributions of $2.9 million.
Interest Expense. Interest expense was $28.8 million during the three months ended September 30, 2011 as compared to $27.4 million during the same period in 2010, an increase of $1.4 million, or 5.1 percent, primarily due to a $3.3 million increase related to the issuance of long-term debt in May 2011 partially offset by a $1.7 million decrease in interest expense due to a higher allowance for borrowed funds used during construction primarily due to construction costs for Crossroads during the three months ended September 30, 2011 as compared to the same period in 2010.

Income Tax Expense. Income tax expense was $70.9 million during the three months ended September 30, 2011 as compared to $62.7 million during the same period in 2010, an increase of $8.2 million, or 13.1 percent. The increase in income tax expense was primarily due to higher pre-tax income during the three months ended September 30, 2011 as compared to the same period in 2010 partially offset by higher Oklahoma investment tax credits during the three months ended September 30, 2011 as compared to the same period in 2010.

Nine Months Ended September 30, 2011 as Compared to Nine Months Ended September 30, 2010
Operating Income

OG&E's operating income increased $42.1 million, or 11.2 percent, during the nine months ended September 30, 2011 as compared to the same period in 2010 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense.

Gross Margin

Gross margin was $957.2 million during the nine months ended September 30, 2011 as compared to $887.0 million during the same period in 2010, an increase of $70.2 million, or 7.9 percent. The gross margin increased primarily due to:

- warmer weather in OG&E's service territory, which increased the gross margin by $24.9 million;

Table of Contents

- increased price variance, which included revenues from various rate riders, including the Windspeed transmission line rider, the Oklahoma demand program rider, the Smart Grid rider, the system hardening rider, the Oklahoma storm recovery rider and the OU Spirit rider, and higher revenues from sales and customer mix, which increased the gross margin by $19.5 million;
- new customer growth in OG&E's service territory, 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 $9.7 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $4.7 million;
- revenues from the Arkansas rate increase, which increased the gross margin by $4.3 million; and
- higher revenues related to the renewal of the Arkansas Valley Electric Cooperative contract (see Note 16 of Notes to Condensed Consolidated Financial Statements), which increased the gross margin by $2.2 million.

These increases in the gross margin were partially offset by a credit to customers related to the settlement of OG&E's 2009 fuel adjustment clause review (see Note 16 of Notes to Condensed Consolidated Financial Statements), which decreased the gross margin by $5.1 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $640.2 million during the nine months ended September 30, 2011 as compared to $622.4 million during the same period in 2010, an increase of $17.8 million, or 2.9 percent, primarily due to higher natural gas and coal generation and higher coal prices partially offset by 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 the Company and its customers. Purchased power costs were $162.7 million during the nine months ended September 30, 2011 as compared to $168.6 million during the same period in 2010, a decrease of $5.9 million, or 3.5 percent, primarily due to a decrease in purchases in the energy imbalance service market and a decrease in cogeneration costs partially offset by an increase in short-term power purchases.

Operating Expenses

Other operation and maintenance expenses were $324.3 million during the nine months ended September 30, 2011 as compared to $305.9 million during the same period in 2010, an increase of $18.4 million, or 6.0 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of $13.0 million in payroll and benefits expense and contract professional services allocated from the holding company;
- an increase of $9.3 million in salaries and wages expense primarily due to salary increases in 2011, increased incentive compensation expense and increased overtime expense primarily due to storms in April and August 2011;
- an increase of $6.0 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- an increase of $1.8 million related to less work being capitalized during the nine months ended September 30, 2011;
- an increase of $1.6 million in uncollectible expense;
- an increase of $1.3 million in fleet transportation expense primarily due to higher fuel costs during the nine months ended September 30, 2011;
- an increase of $1.2 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at some of OG&E's power plants; and
- an increase of $1.1 million in SPP administration fees.

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

- a decrease of $6.9 million in employee benefits expense primarily due to a decrease in postretirement benefits expense related to amendments to the Company's retiree medical plan adopted in January 2011 (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011) partially offset by a modification to OG&E's pension tracker and a decrease in worker's compensation accruals during the nine months ended September 30, 2011;
- an increase of $4.7 million in injuries and damages expense primarily due to higher reserves on claims during the nine months ended September 30, 2010;

Table of Contents

- a decrease of $2.5 million related to decreased spending on vegetation management, related to system hardening, which expenses are being recovered through a rider; and
- a decrease of $1.0 million related to an adjustment during the nine months ended September 30, 2011 to reclassify a portion of Smart Grid costs for the Arkansas jurisdiction to a regulatory asset.

Depreciation and amortization expense was $158.8 million during the nine months ended September 30, 2011 as compared to $153.4 million during the same period in 2010, an increase of $5.4 million, or 3.5 percent, primarily due to additional assets being placed into service throughout 2010 and the nine months ended September 30, 2011, including Windspeed.

Taxes other than income were $56.1 million during the nine months ended September 30, 2011 as compared to $51.8 million during the same period in 2010, an increase of $4.3 million, or 8.3 percent, primarily due to higher ad valorem taxes.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $16.1 million during the nine months ended September 30, 2011 as compared to $7.2 million during the same period in 2010, an increase of $8.9 million, primarily due to construction costs for Crossroads partially offset by the completion of the Windspeed transmission line on March 31, 2010.

Other Income. Other income was $3.2 million during the nine months ended September 30, 2011 as compared to $2.2 million during the same period in 2010, an increase of $1.0 million, or 45.5 percent. The increase in other income was primarily due to a benefit of $5.7 million associated with the tax gross-up of allowance for equity funds used during construction partially offset by increased losses of $4.4 million recognized in the guaranteed flat bill program during the nine months ended September 30, 2011 from higher than expected usage resulting from warmer weather.

Other Expense. Other expense was $4.9 million during the nine months ended September 30, 2011 as compared to $1.4 million during the same period in 2010, an increase of $3.5 million, primarily due to an increase in charitable contributions of $3.3 million.

Interest Expense. Interest expense was $82.2 million during the nine months ended September 30, 2011 as compared to $76.8 million during the same period in 2010, an increase of $5.4 million, or 7.0 percent, primarily due to an $11.0 million increase related to the issuance of long-term debt in June 2010 and May 2011. This increase in interest expense was partially offset by:

- a $4.6 million decrease in interest expense due to a higher allowance for borrowed funds used during construction primarily due to construction costs for Crossroads partially offset by the completion of the Windspeed transmission line on March 31, 2010; and
- a $1.3 million decrease in interest expense during the nine months ended September 30, 2011 due to interest to customers related to the fuel over recovery balance.

Income Tax Expense. Income tax expense was $107.0 million during the nine months ended September 30, 2011 as compared to $103.9 million during the same period in 2010, an increase of $3.1 million, or 3.0 percent. The increase in income tax expense was primarily due to higher pre-tax income during the nine months ended September 30, 2011 as compared to the same period in 2010. This increase in income tax expense was partially offset by:

- the one-time, non-cash charge during the three months ended March 31, 2010 for the elimination of the tax deduction for the Medicare Part D subsidy;
- the write-off of previously recognized Oklahoma investment tax credits during the nine months ended September 30, 2010 primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures; and
- higher Oklahoma investment tax credits during the nine months ended September 30, 2011 as compared to the same period in 2010.

40

Table of Contents

Enogex (Natural Gas Midstream Operations)

Three Months Ended September 30, 2011 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$103.7	$304.9	$160.0	$(109.3)	$459.3
Cost of goods sold	58.6	233.2	163.1	(109.2)	345.7
Gross margin on revenues	45.1	71.7	(3.1)	(0.1)	113.6
Other operation and maintenance	13.7	28.8	1.8	(0.8)	43.5
Depreciation and amortization	5.2	13.4	—	—	18.6
Impairment of assets	—	5.0	—	—	5.0
Taxes other than income	3.5	1.8	0.1	—	5.4
Operating income (loss)	$22.7	$22.7	$(5.0)	$0.7	$41.1

Three Months Ended September 30, 2010 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$103.5	$243.1	$206.5	$(121.1)	$432.0
Cost of goods sold	64.8	178.9	207.6	(121.5)	329.8
Gross margin on revenues	38.7	64.2	(1.1)	0.4	102.2
Other operation and maintenance	11.6	22.0	1.8	(0.6)	34.8
Depreciation and amortization	5.2	12.6	—	—	17.8
Taxes other than income	3.3	1.4	0.1	—	4.8
Operating income (loss)	$18.6	$28.2	$(3.0)	$1.0	$44.8

Nine Months Ended September 30, 2011 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$311.9	$860.7	$526.4	$(367.2)	$1,331.8
Cost of goods sold	192.1	640.4	532.8	(364.9)	1,000.4
Gross margin on revenues	119.8	220.3	(6.4)	(2.3)	331.4
Other operation and maintenance	35.8	81.9	5.9	(2.3)	121.3
Depreciation and amortization	16.4	40.4	—	—	56.8
Impairment of assets	—	5.0	—	—	5.0
Taxes other than income	11.1	5.3	0.3	—	16.7
Operating income (loss)	$56.5	$87.7	$(12.6)	$—	$131.6

Nine Months Ended September 30, 2010 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$311.7	$726.4	$641.2	$(389.7)	$1,289.6
Cost of goods sold	191.9	527.5	644.8	(390.1)	974.1
Gross margin on revenues	119.8	198.9	(3.6)	0.4	315.5
Other operation and maintenance	35.2	66.8	6.6	(2.7)	105.9
Depreciation and amortization	16.0	37.5	—	—	53.5
Taxes other than income	10.6	4.9	0.3	—	15.8
Operating income (loss)	$58.0	$89.7	$(10.5)	$3.1	$140.3

Table of Contents

Operating Data

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Gathered volumes – TBtu/d (A)	1.43	1.34	1.36	1.32
Incremental transportation volumes – TBtu/d (B)	0.67	0.46	0.57	0.44
Total throughput volumes – TBtu/d	2.10	1.80	1.93	1.76
Natural gas processed – TBtu/d	0.79	0.86	0.77	0.81
NGLs sold (keep-whole) – million gallons	48	44	132	137
NGLs sold (purchased for resale) – million gallons	114	119	338	339
NGLs sold (percent-of-liquids) – million gallons	6	7	18	18
NGLs sold (percent-of-proceeds) – million gallons	1	1	3	4
Total NGLs sold – million gallons	169	171	491	498
Average NGLs sales price per gallon	$1.24	$0.92	$1.19	$0.94
Average natural gas sales price per million British thermal unit	$4.30	$4.13	$4.26	$4.46

(A) Trillion British thermal units per day.
(B) Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

Three Months Ended September 30, 2011 as Compared to Three Months Ended September 30, 2010

Operating Income

Enogex’s operating income decreased $3.7 million, or 8.3 percent, during the three months ended September 30, 2011 as compared to the same period in 2010. This decrease was primarily due to higher operation and maintenance expense partially offset by a higher gross margin due to higher average natural gas prices, higher NGLs prices and increased gathered volumes associated with ongoing expansion projects that offset decreased inlet processing volumes due to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire in December 2010 and the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011. 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.

Other operation and maintenance expense increased $8.7 million, or 25.0 percent, primarily due to increased payroll and benefits costs due to increased headcount to support business growth and increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects during the three months ended September 30, 2011.

Impairment of assets was $5.0 million during the three months ended September 30, 2011 with no comparable item in the same period in 2010. The impairment related to the Atoka processing plant as a result of a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka plant and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. The noncontrolling interest portion of the impairment is $2.5 million which is included in Net Income Attributable to Noncontrolling Interests in the Company's Condensed Consolidated Statement of Income.

Transportation and Storage

The transportation and storage business contributed $45.1 million of Enogex's consolidated gross margin during the three months ended September 30, 2011 as compared to $38.7 million in the same period in 2010, an increase of $6.4 million, or 16.5 percent. The transportation operations contributed $37.8 million of Enogex's consolidated gross margin during the three months ended September 30, 2011 as compared to $31.0 million in the same period in 2010. The storage operations contributed $7.3 million of Enogex's consolidated gross margin during the three months ended September 30, 2011 as compared to $7.7 million in the same period in 2010. The gross margin of the transportation and storage business increased primarily due to:

- higher capacity lease services under the MEP and Gulf Crossing capacity leases during the three months ended September 30, 2011 as a result of pipeline integrity work on an Enogex pipeline in 2010, which increased the gross margin by $3.6 million;

Table of Contents

- higher realized margin on sales of physical natural gas long positions associated with transportation operations during the three months ended September 30, 2011, which increased the gross margin by $1.8 million, net of imbalance and fuel tracker obligations; and
- higher firm 311 services due to new contracts with more favorable rates during the three months ended September 30, 2011, which increased the gross margin by $1.7 million.

These gross margin increases in the transportation and storage business were partially offset by lower crosshaul revenues during the three months ended September 30, 2011 as shippers utilized firm 311 services while during the same period in 2010, crosshaul revenues were higher as a result of pipeline integrity work on an Enogex pipeline in 2010 which resulted in shippers utilizing crosshaul services to move gas to other delivery points. The lower crosshaul revenues during the three months ended September 30, 2011 as compared to the same period in 2010 decreased the gross margin by $1.0 million.

Other operation and maintenance expense for the transportation and storage business was $2.1 million, or 18.1 percent, higher during the three months ended September 30, 2011 as compared to the same period in 2010 primarily due to increased payroll and benefits costs due to increased headcount to support business growth.

Gathering and Processing

The gathering and processing business contributed $71.7 million of Enogex's consolidated gross margin during the three months ended September 30, 2011 as compared to $64.2 million in the same period in 2010, an increase of $7.5 million, or 11.7 percent. The gathering operations contributed $31.3 million of Enogex's consolidated gross margin during the three months ended September 30, 2011 as compared to $29.3 million in the same period in 2010. The processing operations contributed $40.4 million of Enogex's consolidated gross margin during the three months ended September 30, 2011 as compared to $34.9 million in the same period in 2010.

During the three months ended September 30, 2011, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of increased volumes from ongoing expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play, which has added richer natural gas to Enogex's system, and higher NGLs prices. Enogex's processing plants saw a decrease in plant inlet volumes as a result of the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire in December 2010 and the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011. Overall, the above factors resulted in an increased gross margin on keep-whole processing of $3.0 million and on percent-of-liquids and percent-of-proceeds contracts of $1.9 million. As previously reported, Enogex converted contracts with one of its five largest customers from keep-whole to fixed fee. This contract conversion resulted in a net reduction of $9.7 million to the processing gross margin during the three months ended September 30, 2011 which is included in the variances above.

Other factors that contributed to the increase in the gathering and processing gross margin were:

- an increase in gathering fees associated with ongoing expansion projects, which increased the gross margin by $3.8 million, of which $1.3 million is associated with the contract conversion discussed above; and
- an increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $2.1 million.

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

- lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations during the three months ended September 30, 2011, which decreased the gross margin by $1.7 million, net of imbalance and fuel tracker obligations; and

- an increase in the utilization of third-party processing as a result of the reduced capacity related to the Cox City processing plant being out of service during the nine months ended September 30, 2011, which decreased the gross margin by $1.4 million.

Other operation and maintenance expense for the gathering and processing business was $6.8 million, or 30.9 percent, higher during the three months ended September 30, 2011 as compared to the same period in 2010 primarily due to increased payroll and benefits costs due to increased headcount to support business growth and increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects during the three months ended September 30, 2011.

Table of Contents

Marketing

The marketing business recognized a loss of $3.1 million as part of Enogex's consolidated gross margin during the three months ended September 30, 2011 as compared to a loss of $1.1 million in the same period in 2010, a decrease in the gross margin of $2.0 million, primarily due to:

- lower realized margin on sale of natural gas inventory from storage due to reduced withdrawal activity, which decreased the gross margin by $3.5 million; and
- a lower of cost or market adjustment on the natural gas storage inventory reflective of higher inventory volumes in 2011, which decreased the gross margin by $1.0 million.

These decreases in the marketing gross margin were partially offset by higher realized gains during the three months ended September 30, 2011 on transportation contracts, which increased the gross margin by $1.5 million.

Enogex Consolidated Information

Interest Expense. Enogex's consolidated interest expense was $5.1 million during the three months ended September 30, 2011 as compared to $7.4 million during the same period in 2010, a decrease of $2.3 million, or 31.1 percent, primarily due to an increase of $2.1 million in capitalized interest related to increased construction activity during the three months ended September 30, 2011.

Income Tax Expense. Enogex's consolidated income tax expense was $13.3 million during the three months ended September 30, 2011 as compared to $14.2 million during the same period in 2010, a decrease of $0.9 million, or 6.3 percent, primarily due to lower pre-tax income during the three months ended September 30, 2011 as compared to the same period in 2010.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $2.7 million during the three months ended September 30, 2011 as compared to $0.4 million during the same period in 2010, an increase of $2.3 million, due to the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by an impairment recorded in August 2011 related to the Atoka processing plant.

Timing Item. Enogex's net income for the three months ended September 30, 2011 was $19.3 million, which included a loss of $1.3 million resulting from recording OER's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

Nine Months Ended September 30, 2011 as Compared to Nine Months Ended September 30, 2010

Operating Income

Enogex’s operating income decreased $8.7 million, or 6.2 percent, during the nine months ended September 30, 2011 as compared to the same period in 2010. This decrease was primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense, lower average natural gas prices and decreased inlet processing volumes due to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire in December 2010 and the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011 partially offset by higher NGLs prices and increased gathered volumes associated with ongoing expansion projects. 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 nine months ended September 30, 2011, volume changes and realized margin on physical gas long/short positions decreased the gross margin by $11.7 million, net of corresponding imbalance and fuel tracker obligations and the impact of the recovery of prior years' under-recovered fuel positions during the nine months ended September 30, 2010.

Other operation and maintenance expense increased $15.4 million, or 14.5 percent, primarily due to increased payroll and benefits costs due to increased headcount to support business growth, increased costs due to remediation projects and increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects during the nine months ended September 30, 2011.

Depreciation and amortization expense increased $3.3 million, or 6.2 percent, primarily due to additional assets placed into service throughout 2010 and the nine months ended September 30, 2011.

Table of Contents

Impairment of assets was $5.0 million during the nine months ended September 30, 2011 with no comparable item in the same period in 2010. The impairment related to the Atoka processing plant as a result of a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka plant and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. The noncontrolling interest portion of the impairment is $2.5 million which is included in Net Income Attributable to Noncontrolling Interests in the Company's Condensed Consolidated Statement of Income.

Transportation and Storage

The transportation and storage business contributed $119.8 million of Enogex's consolidated gross margin during each of the nine months ended September 30, 2011 and 2010. The transportation operations contributed $97.0 million of Enogex's consolidated gross margin during the nine months ended September 30, 2011 as compared to $95.3 million in the same period in 2010. The storage operations contributed $22.8 million of Enogex's consolidated gross margin during the nine months ended September 30, 2011 as compared to $24.5 million in the same period in 2010. Factors affecting the transportation and storage gross margin were:

- higher capacity lease services under the MEP and Gulf Crossing capacity leases during the nine months ended September 30, 2011 as a result of pipeline integrity work on an Enogex pipeline in 2010, which increased the gross margin by $4.7 million;
- higher firm 311 services due to new contracts with more favorable rates during the nine months ended September 30, 2011, which increased the gross margin by $3.3 million;
- higher interruptible transportation fees due to new contracts with more favorable rates during the nine months ended September 30, 2011, which increased the gross margin by $1.4 million;
- lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations during the nine months ended September 30, 2011. Gross margin during the nine months ended September 30, 2011 included the under recovery of fuel positions as compared to the nine months ended September 30, 2010 that included the recovery of prior year's under-recovered fuel positions, which reduced the gross margin in 2011 by $6.0 million, net of imbalance and fuel tracker obligations; and
- lower crosshaul revenues during the nine months ended September 30, 2011 as shippers utilized firm 311 services while during the same period in 2010, crosshaul revenues were higher as a result of pipeline integrity work on an Enogex pipeline in 2010 which resulted in shippers utilizing crosshaul services to move gas to other delivery points. The lower crosshaul revenues during the nine months ended September 30, 2011 as compared to the same period in 2010 decreased the gross margin by $1.0 million.

Gathering and Processing

The gathering and processing business contributed $220.3 million of Enogex's consolidated gross margin during the nine months ended September 30, 2011 as compared to $198.9 million in the same period in 2010, an increase of $21.4 million, or 10.8 percent. The gathering operations contributed $89.7 million of Enogex's consolidated gross margin during the nine months ended September 30, 2011 as compared to $88.5 million in the same period in 2010. The processing operations contributed $130.6 million of Enogex's consolidated gross margin during the nine months ended September 30, 2011 as compared to $110.4 million in the same period in 2010.

During the nine months ended September 30, 2011, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes from ongoing expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play, which has added richer natural gas to Enogex's system, and higher NGLs prices partially offset by lower average natural gas prices. These increases were partially offset by a decrease in inlet volumes as a result of the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire in December 2010 and the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011. Overall, the above factors resulted in an increased gross margin on keep-whole processing of $9.6 million and on percent-of-liquids and percent-of-proceeds contracts of $2.1 million. As previously reported, Enogex converted contracts with one of its five largest customers from keep-whole to fixed fee. This contract conversion resulted in a net reduction of $9.7 million to the processing gross margin during the nine months ended September 30, 2011 which is included in the variances above.

Other factors that contributed to the increase in the gathering and processing gross margin were:

- an increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $9.7 million; and
- an increase in gathering fees associated with ongoing expansion projects, which increased the gross margin by

Table of Contents

$6.9 million, of which $1.3 million is associated with the contract conversion discussed above.

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

- lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin in 2011 by $5.7 million, net of imbalance and fuel tracker obligations; and
- an increase in the utilization of third-party processing as a result of the reduced capacity related to the Cox City processing plant being out of service during the nine months ended September 30, 2011, which decreased the gross margin by $1.6 million.

Other operation and maintenance expense for the gathering and processing business was $15.1 million, or 22.6 percent, higher during the nine months ended September 30, 2011 as compared to the same period in 2010 primarily due to increased payroll and benefits costs due to increased headcount to support business growth, increased costs due to remediation projects and increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects during the nine months ended September 30, 2011.

Marketing

The marketing business recognized a loss of $6.4 million as part of Enogex's consolidated gross margin during the nine months ended September 30, 2011 as compared to a loss of $3.6 million in the same period in 2010, a decrease in the gross margin of $2.8 million, or 77.8 percent. The marketing gross margin decreased primarily due to

- lower realized margin on sale of natural gas inventory from storage due to a reduction in the realized natural gas market spreads, which decreased the gross margin by $1.1 million; and
- a lower of cost or market adjustment on the natural gas storage inventory reflective of higher inventory volumes in 2011, which decreased the gross margin by $1.0 million.

Enogex Consolidated Information

Other Income. Enogex's consolidated other income was $3.8 million during the nine months ended September 30, 2011 as compared to $0.1 million during the same period in 2010, an increase of $3.7 million, 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 April 2011.

Interest Expense. Enogex's consolidated interest expense was $17.2 million during the nine months ended September 30, 2011 as compared to $23.3 million during the same period in 2010, a decrease of $6.1 million, or 26.2 percent, primarily due to:

- an increase of $4.5 million in capitalized interest related to increased construction activity during the nine months ended September 30, 2011; and
- a decrease of $1.0 million in interest expense during the nine months ended September 30, 2011 due to the retirement of long-term debt in January 2010.

Income Tax Expense. Enogex's consolidated income tax expense was $40.2 million during the nine months ended September 30, 2011 as compared to $46.2 million during the same period in 2010, a decrease of $6.0 million, or 13.0 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income during the nine months ended September 30, 2011 as compared to the same period in 2010; and

- the one-time, non-cash charge during the three months ended March 31, 2010 for the elimination of the tax deduction for the Medicare Part-D subsidy.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $13.9 million during the nine months ended September 30, 2011 as compared to $2.0 million during the same period in 2010, an increase of $11.9 million, due to the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by an impairment recorded in August 2011 related to the Atoka processing plant.

Non-Recurring Item. During the nine months ended September 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.

Table of Contents

Timing Item. Enogex's net income for the nine months ended September 30, 2011 was $63.1 million, which included a loss of $1.3 million resulting from recording OER's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

Financial Condition

The balance of Accounts Receivable was $396.4 million and $277.9 million at September 30, 2011 and December 31, 2010, respectively, an increase of $118.5 million, or 42.6 percent, primarily due to an increase in billings to OG&E's customers reflecting warmer weather in OG&E's service territory in September 2011 as compared to December 2010 primarily due to higher usage by OG&E's customers and higher seasonal electric rates.

The balance of Fuel Inventories was $91.0 million and $158.8 million at September 30, 2011 and December 31, 2010, respectively, a decrease of $67.8 million, or 42.7 percent, primarily due to lower coal inventory balances at OG&E from higher coal generation.

The balance of Fuel Clause Under Recoveries was $33.2 million and $1.0 million at September 30, 2011 and December 31, 2010, respectively, an increase of $32.2 million, primarily due to the fact that the amount billed to retail customers was lower than OG&E's cost of fuel. The fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.
The balance of Construction Work in Progress was $874.7 million and $460.0 million at September 30, 2011 and December 31, 2010, respectively, an increase of $414.7 million, or 90.2 percent, primarily due to increased spending on various transmission projects and Crossroads at OG&E and gathering and processing expansion projects at Enogex.

The balance of Regulatory Assets was $415.3 million and $489.4 million at September 30, 2011 and December 31, 2010, respectively, a decrease of $74.1 million, or 15.1 percent, primarily due to amendments to the Company's retiree medical plan adopted in January 2011 (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011).

The balance of Short-Term Debt was $289.0 million and $145.0 million at September 30, 2011 and December 31, 2010, respectively, an increase of $144.0 million, or 99.3 percent, primarily due to an increase in commercial paper borrowings during the nine months ended September 30, 2011 for dividend and bond interest payments, capital expenditures for various transmission projects and Crossroads at OG&E and gathering and processing expansion projects at Enogex and daily operational needs partially offset by proceeds received from the contribution from the ArcLight group in February 2011 and the equity sale of a 0.1 percent membership interest in Enogex Holdings to the ArcLight group in February 2011, a portion of which were used to repay outstanding commercial paper borrowings.

The balance of Accounts Payable was $297.4 million and $321.7 million at September 30, 2011 and December 31, 2010, respectively, a decrease of $24.3 million, or 7.6 percent, primarily due to the timing of outstanding checks clearing the bank.

The balance of Accrued Taxes was $61.6 million and $39.3 million at September 30, 2011 and December 31, 2010, respectively, an increase of $22.3 million, or 56.7 percent, primarily due to ad valorem tax accruals and payments.

The balance of Accrued Interest was $35.1 million and $53.1 million at September 30, 2011 and December 31, 2010, respectively, a decrease of $18.0 million, or 33.9 percent, primarily due to the timing of interest payments on long-term debt in 2011 partially offset by additional interest accrued on long-term debt in 2011.

The balance of Fuel Clause Over Recoveries was $8.5 million and $29.9 million at September 30, 2011 and December 31, 2010, respectively, a decrease of $21.4 million, or 71.6 percent, primarily due to the fact that the amount billed to retail customers was lower than OG&E's cost of fuel. The fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The balance of Other Current Liabilities was $71.3 million and $55.1 million at September 30, 2011 and December 31, 2010, respectively, an increase of $16.2 million, or 29.4 percent, primarily due to the over recovery of various rate riders, primarily the Smart Grid rider.

Table of Contents

The balance of Long-Term Debt was $2,586.9 million and $2,362.9 million at September 30, 2011 and December 31, 2010, respectively, an increase of $224.0 million, or 9.5 percent, due to the issuance of $250 million of long-term debt in May 2011 partially offset by repayments of borrowings under Enogex LLC's revolving credit agreement.
The balance of Accrued Benefit Obligations was $241.5 million and $372.4 million at September 30, 2011 and December 31, 2010, respectively, a decrease of $130.9 million, or 35.2 percent, primarily due to amendments to the Company's retiree medical plan adopted in January 2011 (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011) and Pension Plan contributions during the nine months ended September 30, 2011 partially offset by accruals for pension and postretirement benefits expense.

The balance of Deferred Income Taxes was $1,599.8 million and $1,434.8 million at September 30, 2011 and December 31, 2010, respectively, an increase of $165.0 million, or 11.5 percent, primarily due to accelerated bonus tax depreciation partially offset by the Company being in a tax net operating loss position in 2011.

The balance of Regulatory Liabilities was $223.2 million and $193.1 million at September 30, 2011 and December 31, 2010, respectively, an increase of $30.1 million, or 15.6 percent, primarily due to increases related to removal obligations for OG&E distribution assets and Oklahoma pension regulatory liabilities.
The balance of Accumulated Other Comprehensive Loss was $35.5 million and $60.2 million at September 30, 2011 and December 31, 2010, respectively, a decrease of $24.7 million, or 41.0 percent, primarily due to amendments to the Company's retiree medical plan adopted in January 2011 (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011) and NGLs hedges being realized during the nine months ended September 30, 2011.

The balance of Noncontrolling Interests was $158.0 million and $110.4 million at September 30, 2011 and December 31, 2010, respectively, an increase of $47.6 million, or 43.1 percent, primarily due to the contribution from the ArcLight group in February 2011 and the equity sale of a 0.1 percent membership interest in Enogex Holdings to the ArcLight group in February 2011 partially offset by distributions to the ArcLight group during the nine months ended September 30, 2011.

Off-Balance Sheet Arrangements

Except as discussed below, there have been no significant changes in the Company's off-balance sheet arrangements from those discussed in the Company's 2010 Form 10-K.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,392 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 February 10, 2009, OG&E executed a short-term lease agreement for 270 railcars in accordance with new coal transportation contracts with BNSF Railway and Union Pacific. These railcars were needed to replace railcars that have been taken out of service or destroyed. The lease agreement expired with respect to 135 railcars on November 2, 2009 and was not replaced. The lease agreement with respect to the remaining 135 railcars expired on March 5, 2010 and was subsequently terminated.

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.

Table of Contents

Liquidity and Capital Resources

Cash Flows

	Nine Months Ended September 30,	
(In millions)	2011	2010
Net cash provided from operating activities	$528.7	$586.9
Net cash used in investing activities	(852.3)	(586.0)
Net cash provided from (used in) financing activities	326.9	(50.5)

The decrease of $58.2 million, or 9.9 percent, in net cash provided from operating activities during the nine months ended September 30, 2011 as compared to the same period in 2010 was primarily due to income tax refunds received during the nine months ended September 30, 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures and accelerated tax bonus depreciation partially offset by lower fuel refunds at OG&E during the nine months ended September 30, 2011 as compared to the same period in 2010 and cash received during the nine months ended September 30, 2011 from an increase in billings to OG&E's customers due to warmer weather in OG&E's service territory in 2011.

The increase of $266.3 million, or 45.4 percent, in net cash used in investing activities during the nine months ended September 30, 2011 as compared to the same period in 2010 primarily related to higher levels of capital expenditures during the nine months ended September 30, 2011 related to various transmission projects and Crossroads at OG&E and gathering and processing expansion projects at Enogex.

The increase of $377.4 million in net cash provided from financing activities during the nine months ended September 30, 2011 as compared to the same period in 2010 was primarily due to:

- repayment of the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010;
- an increase in short-term debt borrowings during the nine months ended September 30, 2011 as compared to the same period in 2010;
- contributions from the noncontrolling interest partners during the nine months ended September 30, 2011; and
- a decrease in repayments of borrowings under Enogex LLC's revolving credit agreement during the nine months ended September 30, 2011 as compared to the same period in 2010.

These increases in net cash provided from financing activities were partially offset by lower borrowings under Enogex LLC's revolving credit agreement during the nine months ended September 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 2011 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.

Table of Contents

(In millions)	2011	2012	2013	2014	2015	2016
OG&E Base Transmission	$50	$80	$50	$50	$50	$50
OG&E Base Distribution	195	195	200	200	200	200
OG&E Base Generation	100	110	80	80	80	80
OG&E Other	30	30	30	30	30	30
Total OG&E Base Transmission, Distribution, Generation and Other	375	415	360	360	360	360
OG&E Known and Committed Projects:						
Transmission Projects:						
Sunnyside-Hugo (345 kilovolt)	100	20	—	—	—	—
Sooner-Rose Hill (345 kilovolt)	30	—	—	—	—	—
Balanced Portfolio 3E Projects	45	110	190	45	—	—
SPP Priority Projects	5	20	200	110	—	—
Total Transmission Projects	180	150	390	155	—	—
Other Projects:						
Smart Grid Program (A)	60	90	35	40	20	20
Crossroads	235	40	—	—	—	—
System Hardening	15	15	—	—	—	—
Total Other Projects	310	145	35	40	20	20
Total OG&E Known and Committed Projects	490	295	425	195	20	20
Total OG&E (B)	865	710	785	555	380	380
Enogex LLC Base Maintenance	70	55	60	60	65	70
Enogex LLC Known and Committed Projects:						
Western Oklahoma / Texas Panhandle Gathering Expansion	505	345	130	25	15	10
Other Gathering Expansion	20	65	30	25	25	25
Total Enogex LLC Known and Committed Projects	525	410	160	50	40	35
Total Enogex LLC (C)	595	465	220	110	105	105
OGE Energy	15	20	20	20	20	20
Total capital expenditures	$1,475	$1,195	$1,025	$685	$505	$505

(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 BART requirements due to the uncertainty regarding BART costs. As discussed in "– Environmental Laws and Regulations" below, pursuant to the Oklahoma SIP and the proposed Federal implementation plan, OG&E would be expected to install low NOX burners and related equipment at the three affected generating stations. Preliminary estimates indicate the cost will be between $70 million and $130 million. The proposed Federal implementation plan rejects portions of the Oklahoma SIP with respect to SO2 emissions and, if adopted as proposed, could result in a significant increase in capital expenditures to reduce SO2 emissions. For further information, see "– Environmental Laws and Regulations" below.

(C) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion will 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. Specifically, 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 November 3, 2011 and do not reflect the potential opportunity for a set of growth projects that could materialize.

Pension Plan Funding

In the third quarter of 2011, the Company contributed $10 million to its Pension Plan for a total contribution of $50 million to its Pension Plan during 2011. No additional contributions are expected in 2011.

Security Ratings

Access to reasonably priced capital is dependent in part on credit and security ratings. 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 cost 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 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 September 30, 2011, the Company would have been required to post $6.1 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 September 30, 2011. 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 22, 2011, Fitch Ratings reaffirmed the security ratings of OGE Energy as A, OG&E as A+ and Enogex LLC as BBB. On September 30, 2011, Moody's Investors Services reaffirmed the security ratings of Enogex LLC as Baa3. On October 19, 2011, Moody's Investors Services reaffirmed the security ratings of OGE Energy as Baa1 and OG&E as A2. On October 25, 2011, Standard and Poor's Ratings Services reaffirmed the security ratings of OGE Energy as BBB and OG&E as BBB+ and downgraded Enogex LLC's security rating from BBB+ to BBB- with a stable outlook. Standard and Poor's Ratings Services indicated that the downgrade at Enogex LLC was primarily due to OGE Energy's lower ownership percentage in Enogex which according to Standard and Poor's Ratings Services, over time, lessens the benefit that Enogex receives from OGE Energy's higher credit rating. The downgrade did not trigger any collateral requirements and will not cause a material increase in fees under the revolving credit agreement.

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 and Funding of Benefit Plans

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.

The Company expects to purchase approximately 125,000 shares of its common stock on the open market during the fourth quarter of 2011. These shares will be used to satisfy the Company's obligation to deliver shares of common stock in connection with certain incentive compensation awards.

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 short-term debt balance was $289.0 million and $145.0 million at September 30, 2011 and December 31, 2010, respectively. The weighted-average interest rate on short-term debt at September 30, 2011 was

0.36 percent. The maximum month-end balance of short-term debt during the three months ended September 30, 2011 was $319.8 million. Enogex had $25.0 million in outstanding borrowings under its revolving credit agreement at December 31, 2010 with no outstanding borrowings at September 30, 2011. As Enogex LLC's credit agreement matures on March 31, 2013, 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 September 30, 2011, the Company had $943.8 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 September 30, 2011, the Company had $5.6 million in cash and cash equivalents. See Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

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

Table of Contents

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 are in the valuation of Pension Plan assumptions, impairment estimates, contingency reserves, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of purchase and sale contracts. 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 2010 Form 10-K.

Accounting Pronouncement

See Note 2 of Notes to Condensed Consolidated Financial Statements for a discussion of a recently issued accounting pronouncement that is applicable to the Company.

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-Q and the Company's 2010 Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 15 and 16 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q and Notes 14 and 15 of Notes to Consolidated Financial Statements and Item 3 of Part I of the Company's 2010 Form 10-K for a discussion of the Company's commitments and contingencies.

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 may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. 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 2010 Form 10-K. Except as set forth below and in Part II, Item 1. Legal Proceedings, 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

Hazardous Air Pollutants Emission Standards

On May 3, 2011, the EPA published proposed Maximum Achievable Control Technology regulations governing emissions of certain hazardous air pollutants from electric generating units. The proposal includes numerical standards for particulate matter, hydrogen chloride and mercury emissions from coal-fired boilers. In addition, the proposal includes work practice standards and an annual emission test to control dioxins and furans. Under the proposed rules, compliance is required within three years after finalization of the rule with a possibility of a one year extension. On August 4, 2011, OG&E filed comments with the EPA on the proposed standard. The EPA has not yet issued a final rule but is under a consent decree deadline to do so by December 16, 2011. This deadline is being challenged in court. OG&E cannot predict the outcome of any such challenges and is evaluating what emission controls would be necessary to meet the proposed standards and the associated costs, which could be significant.

Table of Contents

Regional Haze Control Measures

As described in the Company's 2010 Form 10-K, 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 concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners (overfire air and 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 cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be between $70 million and $130 million. With respect to SO2 emissions, the SIP included an agreement between the ODEQ 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 March 22, 2011, the EPA proposed to reject portions of the Oklahoma SIP and proposed a Federal implementation plan. While the EPA accepted Oklahoma's BART determination for NOX in the SIP, it rejected the SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. In its place, the EPA has proposed that OG&E meet an SO2 emission rate of 0.06 pounds per million British thermal unit. 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 cost the Company more than $1.0 billion. On May 23, 2011, OG&E submitted comments on the proposed rule requesting that the Oklahoma SIP be approved and that the EPA not proceed with issuance of the Federal implementation plan. The EPA has not yet issued a final rule approving the SIP and/or promulgating a Federal implementation plan and the consent order date for the EPA's ruling is December 18, 2011. Until the EPA takes final action on the Oklahoma SIP, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty.

National Ambient Air Quality Standards

The EPA is required to set NAAQS for certain pollutants considered to be harmful to public health or the environment. The EPA has designated Oklahoma as being "in attainment" with the current NAAQS for ozone. In March 2008, the EPA issued a final rule lowering the ambient primary and secondary ozone standards NAAQS from current levels. Before Oklahoma's designations of areas as attaining or not attaining the 2008 ozone standards were complete, the EPA announced an intent to reconsider these standards and issue even lower ozone NAAQS. President Obama, however, recently requested that the EPA refrain from issuing revised standards until 2013. The EPA has indicated that it will comply with the President's request. As a result, it is expected that Oklahoma will proceed with the designation of areas as attaining or not attaining the ozone standards established in the 2008 rule. Oklahoma also is working on the designation of areas as attaining or not attaining the NAAQS for SO2 that the EPA finalized in 2010. Neither the outcome nor timing of the ozone and SO2 NAAQS attainment area designation process nor its impact on the Company can be determined with any certainty at this time.

Climate Change and Greenhouse Gas Emissions

In the absence of Federal legislation, the EPA is regulating greenhouse gas emissions from stationary sources using its existing legal authority. On September 22, 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The reporting requirements apply to large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E and Enogex facilities. Pursuant to the rule, the Company began collecting data on January 1, 2010 and submitted its first annual report to the EPA by the September 30, 2011 deadline. For petroleum and natural gas facilities, data collection begins on January 1, 2011, with the first annual report due on March 31, 2012. OG&E already reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program and is continuing to evaluate various options for reducing, avoiding, offsetting or sequestering its carbon dioxide 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. The EPA has not yet issued proposed rules.

Table of Contents

Notice of Violation

As previously reported, in July 2008, the Company 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. 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 (See Part II, Item 1 – Legal Proceedings – Opacity Notice for a related discussion). 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.

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 July 11, 2011, the EPA published a proposed rule in which the EPA proposes to make 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 proposed rule, OG&E would be required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. On August 22, 2011, OG&E filed comments with the EPA on the proposed rule. The Cross-State Air Pollution Rule is currently being challenged in court. OG&E cannot predict the outcome of such challenges and is evaluating what emission controls would be necessary to meet the proposed standards, its ability to comply with the standards in the timeframe proposed by the EPA and the associated costs, which could be significant.

Supreme Court Decision

On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing Federal common law nuisance actions against electrical utility companies based on their alleged contribution to climate change. The Supreme Court's decision, which did not address state law claims, is expected to affect other pending Federal climate change litigation. Although OG&E is not a defendant in any of these proceedings, additional litigation in Federal and state courts over climate change issues is continuing.

Water Intakes

In March 2011, the EPA proposed rules pursuant to Section 316(b) of the Federal Clean Water Act to address impingement and entrainment of aquatic organisms at existing cooling water intake structures. On August 18, 2011, OG&E filed comments with the EPA on the proposed rules. Final rules are currently expected in 2012. When final rules are issued and implemented, additional capital and/or increased operating costs may be incurred. 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 2010 Form 10-K appropriately represent, in all material respects, the market risks affecting the Company.

Commodity Price Risk

The market 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.

Table of Contents

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. Market 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 $0.2 million at September 30, 2011. 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 the commodity price risk of the Company's 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. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $29.6 million at September 30, 2011. This amount represents 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 Part I, Item 3 of the Company's 2010 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.

Table of Contents

1. Opacity Notice. On May 17, 2011, OG&E entered into a Consent Order with the ODEQ related to alleged violations of Federal and state opacity standards from 2005 to present at OG&E's Muskogee and Sooner generating stations. The Consent Order requires OG&E to reach certain milestones with regard to the overall amount of time when opacity exceeds certain amounts. Beginning January 1, 2015, the Consent Order requires each unit at OG&E's Muskogee and Sooner generating stations to have a rolling annual average of the time that opacity emissions are in excess of 20 percent to a level equal to or below one percent of the total time in a measurement period. OG&E agreed to implement two specific projects and other measures as necessary to achieve the milestones established in the Consent Order. These projects and other measures are not expected to involve significant capital or ongoing operating expenses. OG&E also agreed to pay a stipulated cash penalty of $150,000 and agreed to contribute another $150,000 to an ODEQ environmental fund for assisting small Oklahoma communities with their drinking water and wastewater treatment systems. OG&E entered into the Consent Order without admitting or denying the allegations made by the ODEQ. In order to facilitate the court approval of the Consent Order, the ODEQ initiated the necessary legal action against OG&E in state court on May 17, 2011. On June 2, 2011, the Consent Order was approved and entered by the District Court of Oklahoma County, Oklahoma. OG&E considers this matter closed.

As previously reported, on March 18, 2011, the Gulf Coast Environmental Labor Coalition gave notice pursuant to the citizen suit provision of the Federal Clean Air Act that it intended to file a lawsuit against the Company seeking both injunctive relief to enjoin excess opacity emissions from OG&E's Muskogee and Sooner generating stations and the assessment of civil penalties for alleged past violations of the applicable opacity limits. Because the Consent Order addresses the same alleged violations, the legal action by the ODEQ will prevent the Gulf Coast Environmental Labor Coalition from filing the lawsuit against the Company. Neither the ODEQ action against the Company in state court nor the Consent Order preclude the EPA from seeking additional relief in connection with the allegations of opacity emissions not in accordance with applicable new source performance standards that are contained in the previously disclosed notice of violation issued to the Company on April 26, 2011. The EPA has not indicated if it will seek any additional relief related to those allegations.

2. Patent Infringement Case. On September 16, 2011, TransData, Inc., a Texas corporation, sued OG&E in the Western District of Oklahoma, accusing OG&E of infringing three of their U.S. patents by using OG&E's General Electric "smart" meters with Silver Spring Networks wireless modules. The complaint seeks a judgment of infringement, unspecified damages, a permanent injunction, costs and attorneys fees. OG&E was served with the complaint on September 21, 2011 and has notified both General Electric and Silver Springs Network of the lawsuit and its intent to seek indemnity from those companies for any damages that it may incur from this lawsuit. TransData, Inc. has sought to consolidate its OG&E lawsuit with similar lawsuits in the Eastern District of Texas. OG&E has filed a motion for extension of time to answer the complaint. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend this action and believes that its ultimate resolution will not be material to the Company's consolidated financial position or results of operations.

3. Oklahoma Royalty Lawsuit. On July 22, 2005, Enogex, along with certain other unaffiliated co-defendants, was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including Enogex and its subsidiaries, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages, plus attorneys' fees and costs, and punitive damages. Enogex and its subsidiaries filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Company, filed a cross claim against Products seeking indemnification and/or contribution from Products based upon the 1997 sale of a third-party interest in one of Products natural gas processing plants. On May 17, 2006, the plaintiffs

filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex companies filed an answer to the amended petition and BP America, Inc. and BP America Production Company's cross claim on January 16, 2007. On October 14, 2011, this case was dismissed without prejudice. While this lawsuit could be re-filed, Enogex considers the claims and cross claim associated with this lawsuit to be without merit, based upon Enogex's investigation to date. Enogex now considers this case closed.

Item 1A. Risk Factors.

There have been no significant changes in the Company's risk factors from those discussed in the Company's 2010 Form 10-K, which are incorporated herein by reference.

Table of Contents

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

The shares indicated below represent shares of Company common stock purchased on the open market by the trustee for the Company's qualified defined contribution retirement plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company's matching contributions.

	Total Number of	Average Price Paid	Total Number of Shares Purchased as Part of	Approximate Dollar Value of Shares that May Yet Be