

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

**FORM 10-Q**

(Mark One)

**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE  
SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended June 30, 2013**

or

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE  
SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 1-9743



**EOG RESOURCES, INC.**

(Exact name of registrant as specified in its charter)

**Delaware**  
(State or other jurisdiction  
of incorporation or organization)

**47-0684736**  
(I.R.S. Employer  
Identification No.)

**1111 Bagby, Sky Lobby 2, Houston, Texas 77002**  
(Address of principal executive offices) (Zip Code)

**713-651-7000**  
(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. 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). 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  Accelerated filer  Non-accelerated filer  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  No

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

**Title of each class**  
Common Stock, par value \$0.01 per share

**Number of shares**  
272,419,303 (as of July 31, 2013)

**EOG RESOURCES, INC.**

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**PART I. FINANCIAL INFORMATION**

**ITEM 1. FINANCIAL STATEMENTS  
EOG RESOURCES, INC.**

**CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**  
*(In Thousands, Except Per Share Data)*  
*(Unaudited)*

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2013	2012	2013	2012
<b>Net Operating Revenues</b>				
Crude Oil and Condensate	\$ 2,012,999	\$ 1,376,250	\$ 3,794,832	\$ 2,686,585
Natural Gas Liquids	178,457	150,023	347,986	348,333
Natural Gas	462,602	359,421	873,481	726,705
Gains on Mark-to-Market Commodity Derivative Contracts	191,490	188,449	86,534	322,657
Gathering, Processing and Marketing	959,413	710,748	1,882,370	1,428,905
Gains on Asset Dispositions, Net	13,153	113,290	177,386	180,758
Other, Net	22,071	11,138	34,110	22,027
Total	3,840,185	2,909,319	7,196,699	5,715,970
<b>Operating Expenses</b>				
Lease and Well	268,888	250,756	517,888	512,251
Transportation Costs	224,491	135,393	408,748	267,235
Gathering and Processing Costs	25,897	20,588	50,401	46,180
Exploration Costs	47,323	48,149	91,539	90,956
Dry Hole Costs	35,750	11,081	39,712	11,081
Impairments	37,967	54,217	91,515	187,364
Marketing Costs	965,490	694,118	1,870,139	1,399,586
Depreciation, Depletion and Amortization	910,531	808,765	1,756,919	1,557,508
General and Administrative	80,607	75,727	158,592	151,996
Taxes Other Than Income	151,197	118,186	286,128	239,702
Total	2,748,141	2,216,980	5,271,581	4,463,859
Operating Income	1,092,044	692,339	1,925,118	1,252,111
Other Income (Expense), Net	4,833	4,675	(5,301)	15,306
Income Before Interest Expense and Income Taxes	1,096,877	697,014	1,919,817	1,267,417
Interest Expense, Net	61,647	50,775	123,568	101,044
Income Before Income Taxes	1,035,230	646,239	1,796,249	1,166,373
Income Tax Provision	375,538	250,461	641,832	446,586
<b>Net Income</b>	<b>\$ 659,692</b>	<b>\$ 395,778</b>	<b>\$ 1,154,417</b>	<b>\$ 719,787</b>
Net Income Per Share				
Basic	\$ 2.44	\$ 1.48	\$ 4.28	\$ 2.70
Diluted	\$ 2.42	\$ 1.47	\$ 4.24	\$ 2.67
Dividends Declared per Common Share	\$ 0.1875	\$ 0.17	\$ 0.375	\$ 0.34
Average Number of Common Shares				
Basic	270,016	266,874	269,665	266,718
Diluted	272,739	269,985	272,473	270,083
<b>Comprehensive Income</b>				
Net Income	\$ 659,692	\$ 395,778	\$ 1,154,417	\$ 719,787
Other Comprehensive Income (Loss)				
Foreign Currency Translation Adjustments	(19,314)	(28,689)	(33,578)	(2,164)
Foreign Currency Swap Transaction	(662)	(1,431)	1,039	630
Income Tax Related to Foreign Currency Swap Transaction	-	576	-	49
Interest Rate Swap Transaction	584	231	1,321	(364)
Income Tax Related to Interest Rate Swap Transaction	(210)	(83)	(475)	131
Other	27	31	55	58
Other Comprehensive Income (Loss)	(19,575)	(29,365)	(31,638)	(1,660)
<b>Comprehensive Income</b>	<b>\$ 640,117</b>	<b>\$ 366,413</b>	<b>\$ 1,122,779</b>	<b>\$ 718,127</b>

The accompanying notes are an integral part of these consolidated financial statements.

**EOG RESOURCES, INC.**  
**CONSOLIDATED BALANCE SHEETS**  
*(In Thousands, Except Share Data)*  
*(Unaudited)*

	<b>June 30, 2013</b>	<b>December 31, 2012</b>
<b>ASSETS</b>		
<b>Current Assets</b>		
Cash and Cash Equivalents	\$ 1,228,016	\$ 876,435
Accounts Receivable, Net	1,808,954	1,656,618
Inventories	657,400	683,187
Assets from Price Risk Management Activities	105,667	166,135
Income Taxes Receivable	23,450	29,163
Deferred Income Taxes	157,012	-
Other	260,341	178,346
Total	<u>4,240,840</u>	<u>3,589,884</u>
<b>Property, Plant and Equipment</b>		
Oil and Gas Properties (Successful Efforts Method)	40,262,580	38,126,298
Other Property, Plant and Equipment	2,846,971	2,740,619
Total Property, Plant and Equipment	<u>43,109,551</u>	<u>40,866,917</u>
Less: Accumulated Depreciation, Depletion and Amortization	<u>(18,529,163)</u>	<u>(17,529,236)</u>
Total Property, Plant and Equipment, Net	24,580,388	23,337,681
<b>Other Assets</b>	255,924	409,013
<b>Total Assets</b>	<b>\$ <u>29,077,152</u></b>	<b>\$ <u>27,336,578</u></b>
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
<b>Current Liabilities</b>		
Accounts Payable	\$ 2,201,940	\$ 2,078,948
Accrued Taxes Payable	161,608	162,083
Dividends Payable	50,614	45,802
Liabilities from Price Risk Management Activities	5,482	7,617
Deferred Income Taxes	4,310	22,838
Current Portion of Long-Term Debt	406,579	406,579
Other	189,770	200,191
Total	<u>3,020,303</u>	<u>2,924,058</u>
<b>Long-Term Debt</b>	5,906,210	5,905,602
<b>Other Liabilities</b>	795,308	894,758
<b>Deferred Income Taxes</b>	4,970,705	4,327,396
<b>Commitments and Contingencies (Note 8)</b>		
<b>Stockholders' Equity</b>		
Common Stock, \$0.01 Par, 640,000,000 Shares Authorized and 272,611,848 Shares Issued at June 30, 2013 and 271,958,495 Shares Issued at December 31, 2012	202,726	202,720
Additional Paid in Capital	2,576,441	2,500,340
Accumulated Other Comprehensive Income	408,257	439,895
Retained Earnings	11,228,011	10,175,631
Common Stock Held in Treasury, 277,274 Shares at June 30, 2013 and 326,264 Shares at December 31, 2012	<u>(30,809)</u>	<u>(33,822)</u>
Total Stockholders' Equity	<u>14,384,626</u>	<u>13,284,764</u>
<b>Total Liabilities and Stockholders' Equity</b>	<b>\$ <u>29,077,152</u></b>	<b>\$ <u>27,336,578</u></b>

The accompanying notes are an integral part of these consolidated financial statements.

**EOG RESOURCES, INC.**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
*(In Thousands)*  
*(Unaudited)*

	<b>Six Months Ended</b>	
	<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>
<b>Cash Flows from Operating Activities</b>		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	\$ 1,154,417	\$ 719,787
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	1,756,919	1,557,508
Impairments	91,515	187,364
Stock-Based Compensation Expenses	57,724	55,466
Deferred Income Taxes	488,632	278,826
Gains on Asset Dispositions, Net	(177,386)	(180,758)
Other, Net	8,747	(3,404)
Dry Hole Costs	39,712	11,081
Mark-to-Market Commodity Derivative Contracts		
Total Gains	(86,534)	(322,657)
Realized Gains	135,959	306,780
Excess Tax Benefits from Stock-Based Compensation	(21,869)	(22,115)
Other, Net	7,759	9,890
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(164,809)	115,419
Inventories	22,085	(103,576)
Accounts Payable	141,369	176,355
Accrued Taxes Payable	24,816	14,363
Other Assets	(92,305)	(102,303)
Other Liabilities	(51,400)	(27,355)
Changes in Components of Working Capital Associated with Investing and Financing Activities	(19,639)	(97,453)
<b>Net Cash Provided by Operating Activities</b>	<b>3,315,712</b>	<b>2,573,218</b>
<b>Investing Cash Flows</b>		
Additions to Oil and Gas Properties	(3,250,091)	(3,748,278)
Additions to Other Property, Plant and Equipment	(183,516)	(315,542)
Proceeds from Sales of Assets	579,941	1,111,517
Changes in Restricted Cash	(52,322)	-
Changes in Components of Working Capital Associated with Investing Activities	19,358	97,746
<b>Net Cash Used in Investing Activities</b>	<b>(2,886,630)</b>	<b>(2,854,557)</b>
<b>Financing Cash Flows</b>		
Dividends Paid	(97,006)	(88,892)
Excess Tax Benefits from Stock-Based Compensation	21,869	22,115
Treasury Stock Purchased	(21,094)	(22,663)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	20,773	32,986
Repayment of Capital Lease Obligation	(2,866)	-
Other, Net	281	(293)
<b>Net Cash Used in Financing Activities</b>	<b>(78,043)</b>	<b>(56,747)</b>
<b>Effect of Exchange Rate Changes on Cash</b>	<b>542</b>	<b>2,734</b>
<b>Increase (Decrease) in Cash and Cash Equivalents</b>	<b>351,581</b>	<b>(335,352)</b>
<b>Cash and Cash Equivalents at Beginning of Period</b>	<b>876,435</b>	<b>615,726</b>
<b>Cash and Cash Equivalents at End of Period</b>	<b>\$ 1,228,016</b>	<b>\$ 280,374</b>

The accompanying notes are an integral part of these consolidated financial statements.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**  
**(Unaudited)**

**1. Summary of Significant Accounting Policies**

**General.** The consolidated financial statements of EOG Resources, Inc., together with its subsidiaries (collectively, EOG), included herein have been prepared by management without audit pursuant to the rules and regulations of the United States Securities and Exchange Commission (SEC). Accordingly, they reflect all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the financial results for the interim periods presented. Certain information and notes normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) have been condensed or omitted pursuant to such rules and regulations. However, management believes that the disclosures included either on the face of the financial statements or in these notes are sufficient to make the interim information presented not misleading. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto included in EOG's Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 22, 2013 (EOG's 2012 Annual Report).

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The operating results for the three and six months ended June 30, 2013 are not necessarily indicative of the results to be expected for the full year.

**Recently Issued Accounting Standards.** In February 2013, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2013-02 "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" (ASU 2013-02). ASU 2013-02 amends ASU 2011-05 and requires that entities disclose additional information about amounts reclassified out of Accumulated Other Comprehensive Income (AOCI) by component. Significant amounts reclassified out of AOCI are required to be presented either on the face of the Consolidated Statements of Income and Comprehensive Income or in the notes to the financial statements. The requirements of ASU 2013-02 are effective for fiscal years and interim periods in those years beginning after December 15, 2012. EOG adopted the provisions of ASU 2013-02 effective January 1, 2013. The adoption did not have a material impact on EOG's financial statements. No significant amounts were reclassified out of AOCI during the three and six months ended June 30, 2013.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

**2. Stock-Based Compensation**

As more fully discussed in Note 6 to the Consolidated Financial Statements included in EOG's 2012 Annual Report, EOG maintains various stock-based compensation plans. Stock-based compensation expense is included on the Consolidated Statements of Income and Comprehensive Income based upon the job function of the employees receiving the grants as follows (in millions):

	<b>Three Months Ended</b>		<b>Six Months Ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>	<b>2013</b>	<b>2012</b>
Lease and Well	\$ 8.4	\$ 8.0	\$ 18.2	\$ 16.5
Gathering and Processing Costs	0.3	0.3	0.6	0.5
Exploration Costs	6.4	6.3	13.9	12.9
General and Administrative	12.2	12.5	25.0	25.5
Total	<u>\$ 27.3</u>	<u>\$ 27.1</u>	<u>\$ 57.7</u>	<u>\$ 55.4</u>

At the 2013 Annual Meeting of Stockholders, EOG's stockholders approved the Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan). As more fully discussed in the 2008 Plan document, the 2008 Plan, among other things, authorizes an additional 15,500,000 shares of EOG common stock for grant under the 2008 Plan and extends the expiration date of the 2008 Plan to May 2023.

The 2008 Plan provides for grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units, performance units, performance stock and other stock-based awards. At June 30, 2013, approximately 18.7 million common shares remained available for grant under the 2008 Plan. EOG's policy is to issue shares related to the 2008 Plan from either previously authorized unissued shares or treasury shares to the extent treasury shares are available.

**Stock Options and Stock-Settled Stock Appreciation Rights and Employee Stock Purchase Plan.** The fair value of stock option and SAR grants is estimated using the Hull-White II binomial option pricing model. The fair value of Employee Stock Purchase Plan (ESPP) grants is estimated using the Black-Scholes-Merton model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled \$10.4 million and \$10.5 million during the three months ended June 30, 2013 and 2012, respectively, and \$20.8 million and \$21.3 million during the six months ended June 30, 2013 and 2012, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants during the six-month periods ended June 30, 2013 and 2012 are as follows:

	<b>Stock Options/SARs</b>		<b>ESPP</b>	
	<b>Six Months Ended</b>		<b>Six Months Ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>	<b>2013</b>	<b>2012</b>
Weighted Average Fair Value of Grants	\$ 38.66	\$ 35.65	\$ 28.80	\$ 28.24
Expected Volatility	35.82%	39.97%	29.95%	46.42%
Risk-Free Interest Rate	0.48%	0.49%	0.12%	0.06%
Dividend Yield	0.6%	0.7%	0.6%	0.6%
Expected Life	5.5 yrs	5.5 yrs	0.5 yrs	0.5 yrs

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

Expected volatility is based on an equal weighting of historical volatility and implied volatility from traded options in EOG's common stock. The risk-free interest rate is based upon United States Treasury yields in effect at the time of grant. The expected life is based upon historical experience and contractual terms of stock option, SAR and ESPP grants.

The following table sets forth stock option and SAR transactions for the six-month periods ended June 30, 2013 and 2012 (stock options and SARs in thousands):

	<b>Six Months Ended June 30, 2013</b>		<b>Six Months Ended June 30, 2012</b>	
	<b>Number of Stock Options/SARs</b>	<b>Weighted Average Grant Price</b>	<b>Number of Stock Options/SARs</b>	<b>Weighted Average Grant Price</b>
Outstanding at January 1	6,219	\$ 85.81	8,374	\$ 70.01
Granted	31	125.59	46	106.00
Exercised <sup>(1)</sup>	(969)	65.62	(920)	60.34
Forfeited	(56)	96.03	(82)	88.85
Outstanding at June 30 <sup>(2)</sup>	<u>5,225</u>	\$ 89.69	<u>7,418</u>	\$ 71.23
Vested or Expected to Vest <sup>(3)</sup>	<u>4,997</u>	\$ 89.33	<u>7,179</u>	\$ 70.69
Exercisable at June 30 <sup>(4)</sup>	<u>2,255</u>	\$ 79.97	<u>4,379</u>	\$ 60.20

- (1) The total intrinsic value of stock options/SARs exercised for the six months ended June 30, 2013 and 2012 was \$62.1 million and \$45.4 million, respectively. The intrinsic value is based upon the difference between the market price of EOG's common stock on the date of exercise and the grant price of the stock options/SARs.
- (2) The total intrinsic value of stock options/SARs outstanding at June 30, 2013 and 2012 was \$219.5 million and \$147.8 million, respectively. At June 30, 2013 and 2012, the weighted average remaining contractual life was 4.1 years and 3.4 years, respectively.
- (3) The total intrinsic value of stock options/SARs vested or expected to vest at June 30, 2013 and 2012 was \$211.7 million and \$146.7 million, respectively. At June 30, 2013 and 2012, the weighted average remaining contractual life was 4.1 years and 3.3 years, respectively.
- (4) The total intrinsic value of stock options/SARs exercisable at June 30, 2013 and 2012 was \$116.7 million and \$134.3 million, respectively. At June 30, 2013 and 2012, the weighted average remaining contractual life was 2.6 years and 2.0 years, respectively.

At June 30, 2013, unrecognized compensation expense related to non-vested stock option, SAR and ESPP grants totaled \$72.8 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.3 years.

**Restricted Stock and Restricted Stock Units.** Employees may be granted restricted (non-vested) stock and/or restricted stock units without cost to them. Stock-based compensation expense related to restricted stock and restricted stock units totaled \$16.6 million for both the three months ended June 30, 2013 and 2012, and \$36.3 million and \$34.1 million for the six months ended June 30, 2013 and 2012, respectively.



**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

The following table sets forth restricted stock and restricted stock units transactions for the six-month periods ended June 30, 2013 and 2012 (shares and units in thousands):

	<b>Six Months Ended</b>		<b>Six Months Ended</b>	
	<b>June 30, 2013</b>		<b>June 30, 2012</b>	
	<b>Number of</b>	<b>Weighted</b>	<b>Number of</b>	<b>Weighted</b>
	<b>Shares and</b>	<b>Average</b>	<b>Shares and</b>	<b>Average</b>
	<b>Units</b>	<b>Grant Date</b>	<b>Units</b>	<b>Grant Date</b>
		<b>Fair Value</b>		<b>Fair Value</b>
Outstanding at January 1	3,818	\$ 91.06	4,240	\$ 82.93
Granted	265	128.50	290	112.08
Released <sup>(1)</sup>	(293)	123.64	(490)	70.97
Forfeited	(54)	94.39	(75)	88.78
Outstanding at June 30 <sup>(2)</sup>	<u>3,736</u>	<u>\$ 91.11</u>	<u>3,965</u>	<u>\$ 86.42</u>

(1) The total intrinsic value of restricted stock and restricted stock units released for the six months ended June 30, 2013 and 2012 was \$35.4 million and \$55.7 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and restricted stock units are released.

(2) The total intrinsic value of restricted stock and restricted stock units outstanding at June 30, 2013 and 2012 was \$491.9 million and \$357.3 million, respectively.

At June 30, 2013, unrecognized compensation expense related to restricted stock and restricted stock units totaled \$129.9 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.4 years.

**Performance Units and Performance Stock.** As more fully discussed in Note 6 to the Consolidated Financial Statements included in EOG's 2012 Annual Report, in September 2012, EOG granted an aggregate of 54,526 performance units and 16,752 shares of performance stock to its executive officers, which units and shares remained outstanding at June 30, 2013. The fair value of the performance units and performance stock is estimated using a Monte Carlo simulation. Stock-based compensation expense related to performance unit and performance stock grants totaled \$0.3 million for the three months ended June 30, 2013, and \$0.6 million for the six months ended June 30, 2013.

At June 30, 2013, unrecognized compensation expense related to performance units and performance stock totaled \$2.3 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 4.2 years.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

**3. Net Income Per Share**

The following table sets forth the computation of Net Income Per Share for the three-month and six-month periods ended June 30, 2013 and 2012 (in thousands, except per share data):

	<b>Three Months Ended June 30,</b>		<b>Six Months Ended June 30,</b>	
	<b>2013</b>	<b>2012</b>	<b>2013</b>	<b>2012</b>
Numerator for Basic and Diluted Earnings Per Share - Net Income	\$ 659,692	\$ 395,778	\$ 1,154,417	\$ 719,787
Denominator for Basic Earnings Per Share - Weighted Average Shares	270,016	266,874	269,665	266,718
Potential Dilutive Common Shares - Stock Options/SARs	987	1,428	1,050	1,611
Restricted Stock/Units and Performance Units/Stock	1,736	1,683	1,758	1,754
Denominator for Diluted Earnings Per Share - Adjusted Diluted Weighted Average Shares	272,739	269,985	272,473	270,083
Net Income Per Share				
Basic	\$ 2.44	\$ 1.48	\$ 4.28	\$ 2.70
Diluted	\$ 2.42	\$ 1.47	\$ 4.24	\$ 2.67

The diluted earnings per share calculation excludes stock options and SARs that were anti-dilutive. Shares underlying the excluded stock options and SARs totaled 0.1 million and 0.3 million shares for the three months ended June 30, 2013 and 2012, respectively, and 0.1 million and 0.2 million shares for the six months ended June 30, 2013 and 2012, respectively.

**4. Supplemental Cash Flow Information**

Net cash paid for interest and income taxes was as follows for the six-month periods ended June 30, 2013 and 2012 (in thousands):

	<b>Six Months Ended June 30,</b>	
	<b>2013</b>	<b>2012</b>
Interest <sup>(1)</sup>	\$ 121,800	\$ 97,445
Income Taxes, Net of Refunds Received	\$ 173,411	\$ 162,125

(1) Net of capitalized interest of \$22 million and \$24 million for the six months ended June 30, 2013 and 2012, respectively.

EOG's accrued capital expenditures at June 30, 2013 and 2012 were \$724 million and \$857 million, respectively.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

**5. Segment Information**

Selected financial information by reportable segment is presented below for the three-month and six-month periods ended June 30, 2013 and 2012 (in thousands):

	<b>Three Months Ended</b>		<b>Six Months Ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>	<b>2013</b>	<b>2012</b>
<b>Net Operating Revenues</b>				
United States	\$ 3,612,224	\$ 2,660,452	\$ 6,644,076	\$ 5,251,793
Canada	89,140	96,489	272,883	184,559
Trinidad	132,924	146,274	268,272	267,344
Other International <sup>(1)</sup>	5,897	6,104	11,468	12,274
Total	<u>\$ 3,840,185</u>	<u>\$ 2,909,319</u>	<u>\$ 7,196,699</u>	<u>\$ 5,715,970</u>
<b>Operating Income (Loss)</b>				
United States	\$ 1,083,643	\$ 634,927	\$ 1,774,169	\$ 1,165,878
Canada	(20,083)	(14,052)	51,330	(52,636)
Trinidad	71,893	92,947	152,788	170,160
Other International <sup>(1)</sup>	(43,409)	(21,483)	(53,169)	(31,291)
Total	1,092,044	692,339	1,925,118	1,252,111
<b>Reconciling Items</b>				
Other Income (Expense), Net	4,833	4,675	(5,301)	15,306
Interest Expense, Net	61,647	50,775	123,568	101,044
Income Before Income Taxes	<u>\$ 1,035,230</u>	<u>\$ 646,239</u>	<u>\$ 1,796,249</u>	<u>\$ 1,166,373</u>

(1) Other International primarily includes EOG's United Kingdom, China and Argentina operations.

Total assets by reportable segment are presented below at June 30, 2013 and December 31, 2012 (in thousands):

	<b>At</b>	<b>At</b>
	<b>June 30,</b>	<b>December 31,</b>
	<b>2013</b>	<b>2012</b>
<b>Total Assets</b>		
United States	\$ 26,072,533	\$ 24,523,072
Canada	976,093	1,202,031
Trinidad	1,094,649	1,012,727
Other International <sup>(1)</sup>	933,877	598,748
Total	<u>\$ 29,077,152</u>	<u>\$ 27,336,578</u>

(1) Other International primarily includes EOG's United Kingdom, China and Argentina operations.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

**6. Asset Retirement Obligations**

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of short-term and long-term legal obligations associated with the retirement of property, plant and equipment for the six-month periods ended June 30, 2013 and 2012 (in thousands):

	<b>Six Months Ended</b>	
	<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>
Carrying Amount at Beginning of Period	\$ 665,944	\$ 587,084
Liabilities Incurred	24,660	29,799
Liabilities Settled <sup>(1)</sup>	(31,155)	(47,920)
Accretion	17,865	15,316
Revisions	67	52
Foreign Currency Translations	(11,192)	(871)
Carrying Amount at End of Period	<u>\$ 666,189</u>	<u>\$ 583,460</u>
Current Portion	\$ 16,949	\$ 28,496
Noncurrent Portion	\$ 649,240	\$ 554,964

(1) Includes settlements related to asset sales.

The current and noncurrent portions of EOG's asset retirement obligations are included in Current Liabilities - Other and Other Liabilities, respectively, on the Consolidated Balance Sheets.

**7. Exploratory Well Costs**

EOG's net changes in capitalized exploratory well costs for the six-month period ended June 30, 2013 are presented below (in thousands):

	<b>Six Months Ended</b>
	<b>June 30, 2013</b>
Balance at December 31, 2012	\$ 49,116
Additions Pending the Determination of Proved Reserves	69,244
Reclassifications to Proved Properties	(55,555)
Costs Charged to Expense <sup>(1)</sup>	(29,807)
Foreign Currency Translations	(619)
Balance at June 30, 2013	<u>\$ 32,379</u>

(1) Includes capitalized exploratory well costs charged to dry hole costs.

At June 30, 2013, all capitalized exploratory well costs had been capitalized for a period of less than one year.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

**8. Commitments and Contingencies**

There are currently various suits and claims pending against EOG that have arisen in the ordinary course of EOG's business, including contract disputes, personal injury and property damage claims and title disputes. While the ultimate outcome and impact on EOG cannot be predicted, management believes that the resolution of these suits and claims will not, individually or in the aggregate, have a material adverse effect on EOG's consolidated financial position, results of operations or cash flow. EOG records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

**9. Pension and Postretirement Benefits**

EOG has defined contribution pension plans in place for most of its employees in the United States, Canada, Trinidad and the United Kingdom, and defined benefit pension plans covering certain of its employees in Canada and Trinidad. For the six months ended June 30, 2013 and 2012, EOG's total costs recognized for these pension plans were \$20.6 million and \$18.8 million, respectively. EOG also has postretirement medical and dental plans in place for eligible employees in the United States and Trinidad, the costs of which are not material.

**10. Long-Term Debt and Common Stock**

**Long-Term Debt.** During the six months ended June 30, 2013 and 2012, EOG utilized commercial paper, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper issuances at June 30, 2013. The average of the borrowings outstanding under the commercial paper program was \$21 million during the six months ended June 30, 2013. The weighted average interest rate for commercial paper for the six months ended June 30, 2013 was 0.31%. At June 30, 2013, \$350 million principal amount of Floating Rate Senior Notes due 2014 (Floating Rate Notes) and \$150 million principal amount of 4.75% Subsidiary Debt due 2014 (4.75% Subsidiary Debt) were classified as long-term debt based upon EOG's intent and ability to ultimately replace such amounts with other long-term debt.

EOG currently has a \$2.0 billion unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders. The Agreement matures on October 11, 2016 and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods, subject to, among certain other terms and conditions, the consent of the banks holding greater than 50% of the commitments then outstanding under the Agreement. At June 30, 2013, there were no borrowings or letters of credit outstanding under the Agreement. Advances under the Agreement accrue interest based, at EOG's option, on either the London InterBank Offered Rate (LIBOR) plus an applicable margin (Eurodollar rate), or the base rate (as defined in the Agreement) plus an applicable margin. At June 30, 2013, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 1.07% and 3.25%, respectively.

**Restricted Cash.** In May 2013, the Canadian Alberta Energy Regulator (AER) made effective certain regulations affecting the Licensee Liability Rating program which requires well owners to post financial security for well abandonment obligations in amounts set forth by the AER. In order to comply with these requirements, EOG Resources Canada Inc. (EOGRC) established a 160 million Canadian dollar letter of credit facility (maturing May 29, 2018) with Royal Bank of Canada (RBC) as the lender. The letter of credit facility requires EOGRC to deposit cash, in an amount equal to all outstanding letters of credit under such facility, in a cash collateral account at RBC. At June 30, 2013, the balance in this account was 55 million Canadian dollars (52 million United States dollars).

**Common Stock.** On February 13, 2013, EOG's Board of Directors increased the quarterly cash dividend on the Common Stock from the previous \$0.17 per share to \$0.1875 per share, effective with the dividend paid on April 30, 2013 to stockholders of record as of April 16, 2013.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

**11. Fair Value Measurements**

As more fully discussed in Note 12 to the Consolidated Financial Statements included in EOG's 2012 Annual Report, certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the Consolidated Balance Sheets. The following table provides fair value measurement information within the fair value hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at June 30, 2013 and December 31, 2012 (in millions):

	<b>Fair Value Measurements Using:</b>			<b>Total</b>
	<b>Quoted Prices in Active Markets (Level 1)</b>	<b>Significant Other Observable Inputs (Level 2)</b>	<b>Significant Unobservable Inputs (Level 3)</b>	
<b>At June 30, 2013</b>				
Financial Assets:				
Crude Oil Swaps	\$ -	\$ 19	\$ -	\$ 19
Crude Oil Options/Swaptions	-	35	-	35
Natural Gas Options/Swaptions	-	59	-	59
Financial Liabilities:				
Crude Oil Options/Swaptions	\$ -	\$ 5	\$ -	\$ 5
Natural Gas Options/Swaptions	-	1	-	1
Foreign Currency Rate Swap	-	43	-	43
Interest Rate Swap	-	2	-	2
<b>At December 31, 2012</b>				
Financial Assets:				
Crude Oil Swaps	\$ -	\$ 65	\$ -	\$ 65
Crude Oil Options/Swaptions	-	36	-	36
Natural Gas Options/Swaptions	-	65	-	65
Financial Liabilities:				
Crude Oil Options/Swaptions	\$ -	\$ 8	\$ -	\$ 8
Natural Gas Options/Swaptions	-	13	-	13
Foreign Currency Rate Swap	-	55	-	55
Interest Rate Swap	-	4	-	4

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

The estimated fair value of crude oil and natural gas derivative contracts (including options/swaptions) and the interest rate swap contract was based upon forward commodity price and interest rate curves based on quoted market prices. The estimated fair value of the foreign currency rate swap was based upon forward currency rates. Commodity derivative contracts were valued by utilizing an independent third-party derivative valuation provider who uses various types of valuation models, as applicable.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 6.

Proved oil and gas properties and other assets with a carrying amount of \$131 million were written down to their fair value of \$93 million, resulting in pretax impairment charges of \$38 million for the six months ended June 30, 2013. Included in the \$38 million pretax impairment charges is a \$3 million impairment of proved oil and gas properties for which EOG utilized an accepted offer from a third-party purchaser as the basis for determining fair value. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

**Fair Value of Debt.** At both June 30, 2013 and December 31, 2012, EOG had outstanding \$6,290 million aggregate principal amount of debt, which had estimated fair values of approximately \$6,729 million and \$7,032 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable (Level 2) inputs regarding interest rates available to EOG at the end of each respective period.

## **12. Risk Management Activities**

**Commodity Price Risk.** As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's 2012 Annual Report, EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk. EOG has not designated any of its financial commodity derivative contracts as hedges and, accordingly, accounts for financial commodity derivative contracts using the mark-to-market accounting method. In addition to financial transactions, from time to time EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. These physical commodity contracts qualify for the normal purchases and normal sales exception and, therefore, are not subject to hedge accounting or mark-to-market accounting. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

**Commodity Derivative Contracts.** Presented below is a comprehensive summary of EOG's crude oil derivative contracts at June 30, 2013, with notional volumes expressed in barrels per day (Bbld) and prices expressed in dollars per barrel (\$/Bbl).

Crude Oil Derivative Contracts		
	Volume (Bbld)	Weighted Average Price (\$/Bbl)
<u>2013</u> <sup>(1)</sup>		
January 2013 (closed)	101,000	\$99.29
February 1, 2013 through April 30, 2013 (closed)	109,000	99.17
May 1, 2013 through June 30, 2013 (closed)	101,000	99.29
July 1, 2013 through September 30, 2013	111,000	98.25
October 1, 2013 through December 31, 2013	103,000	98.26
<u>2014</u> <sup>(2)</sup>		
January 1, 2014 through March 31, 2014	85,000	\$96.24
April 1, 2014 through June 30, 2014	75,000	\$96.20

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional three-month and six-month periods. Options covering a notional volume of 8,000 Bbld are exercisable on September 30, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 8,000 Bbld at an average price of \$98.11 per barrel for each month during the period October 1, 2013 through December 31, 2013. Options covering a notional volume of 54,000 Bbld are exercisable on December 31, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 54,000 Bbld at an average price of \$98.91 per barrel for each month during the period January 1, 2014 through June 30, 2014.

(2) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional six-month and nine-month periods. Options covering a notional volume of 10,000 Bbld are exercisable on or about March 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 10,000 Bbld at an average price of \$96.60 per barrel for each month during the period April 1, 2014 through December 31, 2014. Options covering a notional volume of 75,000 Bbld are exercisable on or about June 30, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 75,000 Bbld at an average price of \$96.20 per barrel for each month during the period July 1, 2014 through December 31, 2014.



**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

Presented below is a comprehensive summary of EOG's natural gas derivative contracts at June 30, 2013, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu (\$/MMBtu).

Natural Gas Derivative Contracts		
	Volume (MMBtud)	Weighted Average Price (\$/MMBtu)
<u>2013</u> <sup>(1)</sup>		
January 1, 2013 through April 30, 2013 (closed)	150,000	\$4.79
May 1, 2013 through July 31, 2013 (closed)	200,000	4.72
August 1, 2013 through October 31, 2013	200,000	4.72
November 1, 2013 through December 31, 2013	150,000	4.79
<u>2014</u> <sup>(2)</sup>		
January 1, 2014 through December 31, 2014	170,000	\$4.54

- (1) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. For the period August 1, 2013 through October 31, 2013, if the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 200,000 MMBtud at an average price of \$4.72 per MMBtu for each month during that period. For the period November 1, 2013 through December 31, 2013, if the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 150,000 MMBtud at an average price of \$4.79 per MMBtu for each month during that period.
- (2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Additionally, in connection with certain natural gas derivative contracts settled in July 2012, counterparties retain an option of entering into derivative contracts at future dates. All such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 320,000 MMBtud at an average price of \$4.66 per MMBtu for each month during the period January 1, 2014 through December 31, 2014.

**Foreign Currency Exchange Rate Derivative.** EOG is party to a foreign currency aggregate swap with multiple banks to eliminate any exchange rate impacts that may result from the 4.75% Subsidiary Debt issued by one of EOG's Canadian subsidiaries. The foreign currency swap agreement expires on March 15, 2014. EOG accounts for the foreign currency swap transaction using the hedge accounting method. Changes in the fair value of the foreign currency swap do not impact Net Income. The after-tax net impact from the foreign currency swap resulted in a reduction in Other Comprehensive Income (OCI) of \$0.7 million and \$0.9 million for the three months ended June 30, 2013 and 2012, respectively, and increases in OCI of \$1.0 million and \$0.7 million for the six months ended June 30, 2013 and 2012, respectively.

**Interest Rate Derivative.** EOG is a party to an interest rate swap with a counterparty bank. The interest rate swap was entered into in order to mitigate EOG's exposure to volatility in interest rates related to the Floating Rate Notes. The interest rate swap has a notional amount of \$350 million and expires on February 3, 2014. EOG accounts for the interest rate swap transaction using the hedge accounting method. Changes in the fair value of the interest rate swap do not impact Net Income. The after-tax net impact from the interest rate swap resulted in an increase in OCI of \$0.4 million and \$0.1 million for the three months ended June 30, 2013 and 2012, respectively, and an increase of \$0.8 million and a reduction of \$0.2 million for the six months ended June 30, 2013 and 2012, respectively.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)**  
**(Unaudited)**

The following table sets forth the amounts, on a gross basis, and classification of EOG's outstanding derivative financial instruments at June 30, 2013 and December 31, 2012. Certain amounts may be presented on a net basis on the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

<u>Description</u>	<u>Location on Balance Sheet</u>	<u>Fair Value at</u>	
		<u>June 30, 2013</u>	<u>December 31, 2012</u>
Asset Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Assets from Price Risk Management Activities <sup>(1)</sup>	\$ 106	\$ 166
Noncurrent portion	Other Assets <sup>(2)</sup>	\$ 7	\$ -
Liability Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Liabilities from Price Risk Management Activities <sup>(3)</sup>	\$ 5	\$ 8
Noncurrent portion	Other Liabilities <sup>(4)</sup>	\$ 1	\$ 13
Foreign currency swap -			
Current portion	Current Liabilities - Other	\$ 43	\$ -
Noncurrent portion	Other Liabilities	\$ -	\$ 55
Interest rate swap -			
Current portion	Current Liabilities - Other	\$ 2	\$ -
Noncurrent portion	Other Liabilities	\$ -	\$ 4

(1) The current portion of Assets from Price Risk Management Activities consists of gross assets of \$163 million, partially offset by gross liabilities of \$57 million at June 30, 2013 and gross assets of \$271 million, partially offset by gross liabilities of \$105 million at December 31, 2012.

(2) The noncurrent portion of Assets from Price Risk Management Activities consists of gross assets of \$10 million, partially offset by gross liabilities of \$3 million at June 30, 2013.

(3) The current portion of Liabilities from Price Risk Management Activities consists of gross liabilities of \$62 million, partially offset by gross assets of \$57 million at June 30, 2013 and gross liabilities of \$113 million, partially offset by gross assets of \$105 million at December 31, 2012.

(4) The noncurrent portion of Liabilities from Price Risk Management Activities consists of gross liabilities of \$4 million, partially offset by gross assets of \$3 million at June 30, 2013 and gross liabilities of \$13 million at December 31, 2012.

**Credit Risk.** Notional contract amounts are used to express the magnitude of commodity price, foreign currency and interest rate swap agreements. The amounts potentially subject to credit risk, in the event of nonperformance by the counterparties, are equal to the fair value of such contracts (see Note 11). EOG evaluates its exposure to significant counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG requires collateral, parent guarantees or letters of credit to minimize credit risk.

**EOG RESOURCES, INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Concluded)**  
**(Unaudited)**

All of EOG's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDAs) with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDAs may also provide that as a result of certain circumstances, including certain events that cause EOG's credit rating to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDAs to be settled immediately. See Note 11 for the aggregate fair value of all derivative instruments that are in a net liability position at June 30, 2013 and December 31, 2012. EOG held collateral of \$5 million at June 30, 2013 and \$6 million at December 31, 2012. EOG had no collateral posted at both June 30, 2013 and December 31, 2012.

**13. Divestitures**

During the first six months of 2013, EOG received proceeds of approximately \$580 million primarily from the sale of its entire interest in the planned Kitimat liquefied natural gas export terminal, the proposed Pacific Trail Pipelines and approximately 28,500 undeveloped net acres in the Horn River Basin in Canada and from sales of producing properties and acreage in the Upper Gulf Coast region, the Mid-Continent area and the Permian Basin. During the first six months of 2012, EOG received proceeds of approximately \$1,112 million from sales of producing properties and acreage primarily in the Rocky Mountain area, the Upper Gulf Coast region and Canada.

## PART I. FINANCIAL INFORMATION

### ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS EOG RESOURCES, INC.

#### Overview

EOG Resources, Inc., together with its subsidiaries (collectively, EOG), is one of the largest independent (non-integrated) crude oil and natural gas companies in the United States with proved reserves in the United States, Canada, Trinidad, the United Kingdom, China and Argentina. EOG operates under a consistent business and operational strategy that focuses predominantly on maximizing the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term production growth while maintaining a strong balance sheet. EOG implements its strategy by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure that is consistent with prudent and safe operations is also an important goal in the implementation of EOG's strategy.

*United States and Canada.* EOG's efforts to identify plays with large reserve potential have proven to be successful. EOG continues to drill numerous wells in large acreage plays, which in the aggregate are expected to contribute substantially to EOG's crude oil and liquids-rich natural gas production. EOG has placed an emphasis on applying its horizontal drilling and completion expertise to unconventional crude oil and liquids-rich reservoirs. In 2013, EOG is focused on developing its existing North American crude oil and liquids-rich acreage and testing methods to improve the recovery factor of the oil-in-place in these plays. In addition, EOG continues to evaluate certain potential crude oil and, to a lesser extent, liquids-rich exploration and development prospects. For the first half of 2013, revenues from the sales of crude oil and condensate and natural gas liquids (NGLs) were approximately 83% of total wellhead revenues. On a volumetric basis, as calculated using the ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas, crude oil and condensate and NGLs production accounted for approximately 54% of total company production for the first half of 2013 as compared to 44% for the comparable period in 2012. In North America, crude oil and condensate and NGLs production accounted for approximately 61% of total North American production during the first half of 2013 as compared to 51% for the comparable period in 2012. This liquids growth primarily reflects increased production from the South Texas Eagle Ford, the Permian Basin and the North Dakota Bakken. Based on current trends, EOG expects its 2013 crude oil and condensate and NGLs production to continue to increase both in total and as a percentage of total company production as compared to 2012. In 2013, EOG's major producing areas in the United States and Canada are in New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

EOG continues to deliver its crude oil to various markets in the United States, including sales points on the Gulf Coast where sales are based upon the premium Light Louisiana Sweet crude oil index. EOG's crude-by-rail facilities provide EOG the ability to direct its crude oil shipments via rail car to the most favorable markets, including the Gulf Coast, Cushing, Oklahoma, and other markets.

In December 2012, EOG's wholly-owned Canadian subsidiary signed a purchase and sale agreement for the sale of its entire interest in the planned Kitimat liquefied natural gas export terminal, the proposed Pacific Trail Pipelines and approximately 28,500 undeveloped net acres in the Horn River Basin. The transaction closed in February 2013 and is subject to customary post-closing adjustments.

*International.* In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium Block, Modified U(a) Block, Block 4(a) and Modified U(b) Block, as well as in the Pelican Field and the EMZ Area, have been developed and are producing natural gas sold to the National Gas Company of Trinidad and Tobago and condensate sold to the Petroleum Company of Trinidad and Tobago. During the first half of 2013, EOG continued its four-well program in the Modified U(a) Block, drilling three development wells and one successful exploratory well. EOG expects to complete all four wells during the second half of 2013 with initial production commencing in the third quarter.

In the United Kingdom, EOG continues to make progress in field development for its East Irish Sea Conwy crude oil discovery. Modifications to the nearby third-party-owned Douglas platform, which will be used to process Conwy production, began in the first quarter of 2013. First production from the Conwy field is anticipated in mid-2014. In the second quarter of 2013, costs totaling \$24.1 million associated with the Central North Sea Columbus natural gas project were written off. In the Central North Sea Block 21/12b awarded to EOG in 2009, EOG plans to drill an exploratory well in the second half of 2013. EOG will operate this well.

EOG's activity in Argentina is focused on the Vaca Muerta oil shale formation in the Neuquén Basin in Neuquén Province. In 2012, a monitor well was drilled and one horizontal well was drilled and completed in the Aguada del Chivato Block. EOG completed the monitor well during the first half of 2013 and is currently evaluating these wells. Also, two additional wells are planned for 2013, one in the Cerro Avispa Block and one in the Bajo del Toro Block.

During the first quarter of 2013, EOG successfully recompleted a well in the Sichuan Basin, Sichuan Province, The People's Republic of China. Two additional wells are planned in the fourth quarter of 2013.

EOG continues to evaluate other select crude oil and natural gas opportunities outside the United States and Canada primarily by pursuing exploitation opportunities in countries where indigenous crude oil and natural gas reserves have been identified.

*Capital Structure.* One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. EOG's debt-to-total capitalization ratio was 31% and 32% at June 30, 2013 and December 31, 2012, respectively. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity. At June 30, 2013, \$350 million principal amount of Floating Rate Senior Notes due 2014 and \$150 million principal amount of 4.75% Subsidiary Debt due 2014 were classified as long-term debt based upon EOG's intent and ability to ultimately replace such amounts with other long-term debt.

EOG's total anticipated 2013 capital expenditures are estimated to range from \$7.0 billion to \$7.2 billion, excluding acquisitions. The majority of 2013 expenditures have been and will be focused on United States crude oil and, to a lesser extent, liquids-rich natural gas drilling activity. EOG expects capital expenditures to be greater than cash flow from operating activities for 2013. EOG's business plan includes selling certain non-core assets in 2013 to cover the anticipated shortfall. In the first half of 2013, EOG achieved this goal by receiving proceeds of approximately \$580 million from sales of assets. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under its \$2.0 billion senior unsecured revolving credit facility and equity and debt offerings. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

## **Results of Operations**

The following review of operations for the three and six months ended June 30, 2013 and 2012 should be read in conjunction with the consolidated financial statements of EOG and notes thereto included in this Quarterly Report on Form 10-Q.

### ***Three Months Ended June 30, 2013 vs. Three Months Ended June 30, 2012***

***Net Operating Revenues.*** During the second quarter of 2013, net operating revenues increased \$931 million, or 32%, to \$3,840 million from \$2,909 million for the same period of 2012. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, natural gas liquids and natural gas, for the second quarter of 2013 increased \$768 million, or 41%, to \$2,654 million from \$1,886 million for the same period of 2012. During the second quarter of 2013, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of \$191 million compared to \$188 million for the same period of 2012. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party crude oil and condensate, natural gas liquids and natural gas as well as fees associated with gathering third-party natural gas, for the second quarter of 2013 increased \$248 million, or 35%, to \$959 million from \$711 million for the same period of 2012. Gains on asset dispositions, net, for the second quarter of 2013 totaled \$13 million.

Wellhead volume and price statistics for the three-month periods ended June 30, 2013 and 2012 were as follows:

	Three Months Ended June 30,	
	2013	2012
Crude Oil and Condensate Volumes (MBbld) <sup>(1)</sup>		
United States	206.5	150.5
Canada	6.4	6.4
Trinidad	1.4	1.7
Other International <sup>(2)</sup>	0.1	0.1
Total	214.4	158.7
Average Crude Oil and Condensate Prices (\$/Bbl) <sup>(3)</sup>		
United States	\$ 103.73	\$ 95.80
Canada	89.66	82.78
Trinidad	86.96	88.68
Other International <sup>(2)</sup>	92.28	91.20
Composite	103.19	95.20
Natural Gas Liquids Volumes (MBbld) <sup>(1)</sup>		
United States	63.7	54.6
Canada	1.0	0.9
Total	64.7	55.5
Average Natural Gas Liquids Prices (\$/Bbl) <sup>(3)</sup>		
United States	\$ 30.19	\$ 33.54
Canada	39.49	42.89
Composite	30.33	33.72
Natural Gas Volumes (MMcfd) <sup>(1)</sup>		
United States	928	1,070
Canada	79	96
Trinidad	346	422
Other International <sup>(2)</sup>	8	10
Total	1,361	1,598
Average Natural Gas Prices (\$/Mcf) <sup>(3)</sup>		
United States	\$ 3.73	\$ 2.09
Canada	3.17	2.21
Trinidad	3.82	3.42
Other International <sup>(2)</sup>	6.81	5.64
Composite	3.73	2.47
Crude Oil Equivalent Volumes (MBoed) <sup>(4)</sup>		
United States	424.8	383.3
Canada	20.6	23.4
Trinidad	59.0	72.0
Other International <sup>(2)</sup>	1.5	1.8
Total	505.9	480.5
Total MMBoe <sup>(4)</sup>	46.0	43.7

(1) Thousand barrels per day or million cubic feet per day, as applicable.

(2) Other International includes EOG's United Kingdom, China and Argentina operations.

(3) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments.

(4) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, natural gas liquids and natural gas. Crude oil equivalents are determined using the ratio of 1.0 barrel of crude oil and condensate or natural gas liquids to 6.0 thousand cubic feet of natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

Wellhead crude oil and condensate revenues for the second quarter of 2013 increased \$637 million, or 46%, to \$2,013 million from \$1,376 million for the same period of 2012, due to an increase of 56 MBbld, or 35%, in wellhead crude oil and condensate deliveries (\$481 million) and a higher composite average wellhead crude oil and condensate price (\$156 million). The increase in deliveries primarily reflects increased production in the South Texas Eagle Ford, the Permian Basin and the North Dakota Bakken. EOG's composite average wellhead crude oil and condensate price for the second quarter of 2013 increased 8% to \$103.19 per barrel compared to \$95.20 per barrel for the same period of 2012.

NGLs revenues for the second quarter of 2013 increased \$28 million, or 19%, to \$178 million from \$150 million for the same period of 2012, due to an increase of 9 MBbld, or 17%, in NGLs deliveries (\$48 million), partially offset by a lower composite average natural gas liquids price (\$20 million). The increase in deliveries primarily reflects increased volumes in the South Texas Eagle Ford, the Permian Basin and the North Dakota Bakken. EOG's composite average NGLs price for the second quarter of 2013 decreased 10% to \$30.33 per barrel compared to \$33.72 per barrel for the same period of 2012.

Wellhead natural gas revenues for the second quarter of 2013 increased \$103 million, or 29%, to \$463 million from \$359 million for the same period of 2012. The increase was due to a higher composite average wellhead natural gas price (\$156 million), partially offset by a decrease in natural gas deliveries (\$53 million). EOG's composite average wellhead natural gas price for the second quarter of 2013 increased 51% to \$3.73 per thousand cubic feet (Mcf) compared to \$2.47 per Mcf for the same period of 2012. Natural gas deliveries for the second quarter of 2013 decreased 237 MMcfd, or 15%, to 1,361 MMcfd from 1,598 MMcfd for the same period of 2012. The decrease was primarily due to lower production in the United States (142 MMcfd), Trinidad (76 MMcfd) and Canada (17 MMcfd). The decrease in the United States was primarily attributable to asset sales and reduced natural gas drilling activity. The decrease in Trinidad was primarily attributable to higher contractual deliveries in 2012. The decrease in Canada was primarily due to reduced drilling activity in Alberta and the Horn River Basin area.

During the second quarter of 2013, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of \$191 million compared to \$188 million for the same period of 2012. During the second quarter of 2013, the net cash inflow related to settled crude oil and natural gas derivative contracts was \$69 million compared to \$173 million for the same period of 2012.

Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, NGLs and natural gas, as well as fees associated with gathering third-party natural gas. Gathering, processing and marketing revenues were primarily related to sales of third-party crude oil and natural gas. Purchases and sales of third-party crude oil and natural gas are utilized in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities. Marketing costs represent the costs of purchasing third-party crude oil and natural gas and the associated transportation costs.

During the second quarter of 2013, gathering, processing and marketing revenues and marketing costs increased compared to the same period of 2012 primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the second quarter of 2013 decreased \$23 million compared to the same period of 2012 due to lower margins on crude oil marketing activities.



**Operating and Other Expenses.** For the second quarter of 2013, operating expenses of \$2,748 million were \$531 million higher than the \$2,217 million incurred during the second quarter of 2012. The following table presents the costs per barrel of oil equivalent (Boe) for the three-month periods ended June 30, 2013 and 2012:

	<b>Three Months Ended</b>	
	<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>
Lease and Well	\$ 5.84	\$ 5.81
Transportation Costs	4.88	3.14
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	19.23	17.95
Other Property, Plant and Equipment	0.55	0.79
General and Administrative (G&A)	1.75	1.76
Interest Expense, Net	1.34	1.18
Total <sup>(1)</sup>	<u>\$ 33.59</u>	<u>\$ 30.63</u>

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net, for the three months ended June 30, 2013, compared to the same period of 2012 are set forth below.

Lease and well expenses include expenses for EOG-operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expenses can be divided into the following categories: costs to operate and maintain crude oil and natural gas wells, the cost of workovers and lease and well administrative expenses. Operating and maintenance costs include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep and fuel and power. Workovers are operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuates from time to time as EOG attempts to maintain and increase production while maintaining efficient, safe and environmentally responsible operations. EOG continues to increase its operating activities by drilling new wells in existing and new areas. Operating and maintenance costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time. In general, operating and maintenance costs for wells producing crude oil are higher than operating and maintenance costs for wells producing natural gas.

Lease and well expenses of \$269 million for the second quarter of 2013 increased \$18 million from \$251 million for the same prior year period primarily due to increased operating and maintenance costs in the United States (\$10 million) and Canada (\$3 million), increased workover expenditures in the United States (\$4 million) and increased lease and well administrative expenses (\$2 million).

Transportation costs represent costs associated with the delivery of hydrocarbon products from the lease to a downstream point of sale. Transportation costs include transportation fees, costs associated with crude-by-rail operations, the cost of compression (the cost of compressing natural gas to meet pipeline pressure requirements), dehydration (the cost associated with removing water from natural gas to meet pipeline requirements), gathering fees and fuel costs.

Transportation costs of \$224 million for the second quarter of 2013 increased \$89 million from \$135 million for the same prior year period primarily due to increased transportation costs related to production from the South Texas Eagle Ford (\$44 million), the Rocky Mountain area (\$30 million) and the Fort Worth Basin Barnett Shale area (\$13 million).

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual DD&A group calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles, drilling or acquisition of new wells, disposition of existing wells, reserve revisions (upward or downward) primarily related to well performance, economic factors and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from year to year. DD&A of the cost of other property, plant and equipment is generally calculated using the straight-line depreciation method over the useful lives of the assets.

DD&A expenses for the second quarter of 2013 increased \$102 million to \$911 million from \$809 million for the same prior year period. DD&A expenses associated with oil and gas properties for the second quarter of 2013 were \$111 million higher than the same prior year period primarily as a result of increased production in the United States (\$85 million) and higher unit rates in the United States (\$27 million) and Trinidad (\$10 million), partially offset by decreased production in Trinidad (\$7 million) and Canada (\$7 million). Unit rates increased due primarily to downward revisions of natural gas reserves at December 31, 2012, and an increase in production from higher-cost properties.

G&A expenses of \$81 million for the second quarter of 2013 increased \$5 million compared to the same prior year period primarily due to higher costs associated with supporting expanding operations.

Interest expense, net, of \$62 million for the second quarter of 2013 increased \$11 million compared to the same prior year period primarily due to a higher average debt balance.

Gathering and processing costs represent operating and maintenance expenses and administrative expenses associated with operating EOG's gathering and processing assets.

Gathering and processing costs increased \$5 million to \$26 million for the second quarter of 2013 compared to \$21 million for the same prior year period. The increase primarily reflects increased activities in the South Texas Eagle Ford.

Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties and other assets. Unproved properties with individually significant acquisition costs are amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a DD&A group level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated by using the Income Approach as described in the Fair Value Measurement Topic of the Financial Accounting Standards Board's Accounting Standards Codification. For certain assets held for sale, EOG utilized accepted bids as the basis for determining fair value.

Impairments of \$38 million for the second quarter of 2013 were \$16 million lower than impairments for the same prior year period primarily due to decreased impairments of proved properties in the United States (\$17 million) and decreased amortization of unproved property costs in the United States (\$5 million), partially offset by increased impairments of proved properties in Argentina (\$6 million). EOG recorded impairments of proved properties of \$11 million and \$21 million for the second quarter of 2013 and 2012, respectively.

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are generally determined based on wellhead revenues, and ad valorem/property taxes are generally determined based on the valuation of the underlying assets.

Taxes other than income for the second quarter of 2013 increased \$33 million to \$151 million (5.7% of wellhead revenues) compared to \$118 million (6.3% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to increased severance/production taxes in the United States (\$25 million) primarily as a result of increased wellhead revenues and increased ad valorem/property taxes in the United States (\$7 million).

Income tax provision of \$376 million for the second quarter of 2013 increased \$125 million compared to the same period of 2012 due primarily to higher pretax income. The net effective tax rate for the second quarter of 2013 decreased to 36% from 39% for the same prior year period.

***Six Months Ended June 30, 2013 vs. Six Months Ended June 30, 2012***

***Net Operating Revenues.*** During the first six months of 2013, net operating revenues increased \$1,481 million, or 26%, to \$7,197 million from \$5,716 million for the same period of 2012. Total wellhead revenues for the first six months of 2013 increased \$1,254 million, or 33%, to \$5,016 million from \$3,762 million for the same period of 2012. During the first six months of 2013, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of \$87 million compared to net gains of \$323 million for the same period of 2012. Gathering, processing and marketing revenues for the first six months of 2013 increased \$453 million, or 32%, to \$1,882 million from \$1,429 million for the same period of 2012. Gains on asset dispositions, net, of \$177 million for the first six months of 2013 primarily consist of gains on asset dispositions in Canada and Texas.

Wellhead volume and price statistics for the six-month periods ended June 30, 2013 and 2012 were as follows:

	<b>Six Months Ended</b>	
	<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>
<b>Crude Oil and Condensate Volumes (MBbld)</b>		
United States	192.4	140.7
Canada	7.1	7.0
Trinidad	1.3	1.9
Other International	0.1	0.1
Total	200.9	149.7
<b>Average Crude Oil and Condensate Prices (\$/Bbl) <sup>(1)</sup></b>		
United States	\$ 105.04	\$ 98.61
Canada	87.29	86.33
Trinidad	90.36	94.76
Other International	93.56	96.49
Composite	104.31	98.00
<b>Natural Gas Liquids Volumes (MBbld)</b>		
United States	61.2	52.4
Canada	0.9	0.9
Total	62.1	53.3
<b>Average Natural Gas Liquids Prices (\$/Bbl)</b>		
United States	\$ 30.87	\$ 38.12
Canada	40.62	46.54
Composite	31.02	38.27
<b>Natural Gas Volumes (MMcfd)</b>		
United States	931	1,067
Canada	79	100
Trinidad	349	396
Other International	8	10
Total	1,367	1,573
<b>Average Natural Gas Prices (\$/Mcf) <sup>(1)</sup></b>		
United States	\$ 3.41	\$ 2.28
Canada	3.21	2.33
Trinidad	3.86	3.21
Other International	6.78	5.72
Composite	3.53	2.54
<b>Crude Oil Equivalent Volumes (MBoed)</b>		
United States	408.8	370.9
Canada	21.2	24.6
Trinidad	59.4	67.9
Other International	1.4	1.8
Total	490.8	465.2
Total MMBoe	88.8	84.7

(1) Excludes the impact of financial commodity derivative instruments.

Wellhead crude oil and condensate revenues for the first six months of 2013 increased \$1,108 million, or 41%, to \$3,795 million from \$2,687 million for the same period of 2012, due to an increase of 51 MBbld, or 34%, in wellhead crude oil and condensate deliveries (\$878 million) and a higher composite average wellhead crude oil and condensate price (\$230 million). The increase in deliveries primarily reflects increased production from the South Texas Eagle Ford, the Permian Basin and the North Dakota Bakken. EOG's composite average wellhead crude oil and condensate price for the first six months of 2013 increased 6% to \$104.31 per barrel compared to \$98.00 per barrel for the same period of 2012.

Wellhead natural gas revenues for the first six months of 2013 increased \$146 million, or 20%, to \$873 million from \$727 million for the same period of 2012. The increase was due to a higher composite average wellhead natural gas price (\$245 million), partially offset by decreased natural gas deliveries (\$98 million). EOG's composite average wellhead natural gas price for the first six months of 2013 increased 39% to \$3.53 per Mcf compared to \$2.54 per Mcf for the same period of 2012. Natural gas deliveries for the first six months of 2013 decreased 206 MMcfd, or 13%, to 1,367 MMcfd from 1,573 MMcfd for the same period of 2012. The decrease was primarily due to decreased production in the United States (136 MMcfd), Trinidad (47 MMcfd) and Canada (21 MMcfd). The decrease in the United States was primarily attributable to asset sales and reduced natural gas drilling activity. The decrease in Trinidad was primarily attributable to higher contractual deliveries in 2012. The decrease in Canada was due to reduced drilling activity in Alberta and the Horn River Basin area.

During the first six months of 2013, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of \$87 million compared to \$323 million for the same period of 2012. During the first six months of 2013, the net cash inflow related to settled crude oil and natural gas derivative contracts was \$136 million compared to \$307 million for the same period of 2012.

During the first six months of 2013, gathering, processing and marketing revenues and marketing costs increased compared to the same period of 2012 primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the first six months of 2013 decreased \$17 million compared to the same period of 2012 due to lower margins on crude oil marketing activities.

**Operating and Other Expenses.** For the first six months of 2013, operating expenses of \$5,272 million were \$808 million higher than the \$4,464 million incurred during the same period of 2012. The following table presents the costs per Boe for the six-month periods ended June 30, 2013 and 2012:

	<b>Six Months Ended</b>	
	<b>June 30,</b>	
	<b>2013</b>	<b>2012</b>
Lease and Well	\$ 5.83	\$ 6.08
Transportation Costs	4.60	3.17
DD&A -		
Oil and Gas Properties	19.19	17.65
Other Property, Plant and Equipment	0.58	0.85
G&A	1.79	1.80
Interest Expense, Net	1.39	1.20
Total <sup>(1)</sup>	<u>\$ 33.38</u>	<u>\$ 30.75</u>

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net, for the six months ended June 30, 2013, compared to the same period of 2012 are set forth below.

Lease and well expenses of \$518 million for the first six months of 2013 increased \$6 million from \$512 million for the same prior year period primarily due to higher lease and well administrative expenses in the United States.

Transportation costs of \$409 million for the first six months of 2013 increased \$142 million from \$267 million for the same prior year period primarily due to increased transportation costs related to production from the South Texas Eagle Ford (\$63 million), the Rocky Mountain area (\$55 million) and the Fort Worth Basin Barnett Shale area (\$21 million).

DD&A expenses for the first six months of 2013 increased \$199 million to \$1,757 million from \$1,558 million for the same prior year period. DD&A expenses associated with oil and gas properties for the first six months of 2013 were \$219 million higher than the same prior year period primarily as a result of increased production in the United States (\$132 million) and higher unit rates in the United States (\$95 million) and Trinidad (\$23 million), partially offset by decreased production in Canada (\$16 million) and Trinidad (\$8 million) and lower unit rates in Canada (\$13 million). Unit rates increased due primarily to downward revisions of natural gas reserves at December 31, 2012, and an increase in production from higher-cost properties.

G&A expenses of \$159 million for the first six months of 2013 increased \$7 million compared to the same prior year period primarily due to higher costs associated with supporting expanding operations.

Interest expense, net, of \$124 million for the first six months of 2013 increased \$23 million compared to the same prior year period primarily due to a higher average debt balance (\$19 million) and lower capitalized interest (\$2 million).

Gathering and processing costs for the first six months of 2013 increased \$4 million to \$50 million compared to the same prior year period primarily due to increased activities in the South Texas Eagle Ford.

Impairments of \$92 million for the first six months of 2013 were \$96 million lower than impairments for the same prior year period primarily due to decreased impairments of proved properties and other assets in the United States (\$96 million) and decreased amortization of unproved property costs in the United States (\$17 million), partially offset by increased impairments of proved properties in Canada (\$13 million) and Argentina (\$6 million). EOG recorded impairments of proved properties and other assets of \$38 million and \$115 million for the first six months of 2013 and 2012, respectively.

Taxes other than income for the first six months of 2013 increased \$46 million to \$286 million (5.7% of wellhead revenues) from \$240 million (6.4% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to increased severance/production taxes in the United States (\$42 million) primarily as a result of increased wellhead revenues, higher ad valorem/property taxes in the United States (\$7 million) and a decrease in credits available to EOG in 2013 for Texas high-cost gas severance tax rate reductions (\$3 million), partially offset by decreased severance/production taxes in Trinidad (\$4 million).

Other income (expense), net for the first six months of 2013 declined \$21 million compared to the same prior year period. The decrease was primarily due to an increase in foreign currency transaction losses.

Income tax provision of \$642 million for the first six months of 2013 increased \$195 million compared to 2012 due primarily to higher pretax income. The net effective tax rate for the first six months of 2013 decreased to 36% from 38% for the same prior year period.

## Capital Resources and Liquidity

**Cash Flow.** The primary sources of cash for EOG during the six months ended June 30, 2013 were funds generated from operations, proceeds from asset sales and proceeds from stock options exercised and employee stock purchase plan activity. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; dividend payments to stockholders; and purchases of treasury stock in connection with stock compensation plans. During the first six months of 2013, EOG's cash balance increased \$352 million to \$1,228 million from \$876 million at December 31, 2012.

Net cash provided by operating activities of \$3,316 million for the first six months of 2013 increased \$742 million compared to the same period of 2012 primarily reflecting an increase in wellhead revenues (\$1,254 million), partially offset by an increase in cash operating expenses (\$201 million), an unfavorable change in net cash flow from the settlement of financial commodity derivative contracts (\$171 million), unfavorable changes in working capital and other assets and liabilities (\$125 million), an increase in net cash paid for interest expense (\$24 million) and an increase in net cash paid for income taxes (\$11 million).

Net cash used in investing activities of \$2,887 million for the first six months of 2013 increased by \$32 million compared to the same period of 2012 due primarily to a decrease in proceeds from sales of assets (\$532 million), unfavorable changes in working capital associated with investing activities (\$78 million) and an increase in restricted cash (\$52 million), partially offset by a decrease in additions to oil and gas properties (\$498 million) and a decrease in additions to other property, plant and equipment (\$132 million).

Net cash used in financing activities of \$78 million for the first six months of 2013 included cash dividend payments (\$97 million) and the purchase of treasury stock in connection with stock compensation plans (\$21 million). Cash provided by financing activities for the first six months of 2013 included excess tax benefits from stock-based compensation (\$22 million) and proceeds from stock options exercised and employee stock purchase plan activity (\$21 million). Net cash used in financing activities of \$57 million for the first six months of 2012 included cash dividend payments (\$89 million) and purchases of treasury stock in connection with stock compensation plans (\$23 million). Cash provided by financing activities for the first six months of 2012 included proceeds from stock options exercised and employee stock purchase plan activity (\$33 million) and excess tax benefits from stock-based compensation (\$22 million).

**Total Expenditures.** For the year 2013, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately \$7.0 billion to \$7.2 billion, excluding acquisitions. The table below sets out components of total expenditures for the six-month periods ended June 30, 2013 and 2012 (in millions):

<u>Expenditure Category</u>	<u>Six Months Ended</u>	
	<u>2013</u>	<u>2012</u>
Capital		
Drilling and Facilities	\$ 2,997	\$ 3,438
Leasehold Acquisitions	188	275
Property Acquisitions	3	-
Capitalized Interest	22	24
Subtotal	<u>3,210</u>	<u>3,737</u>
Exploration Costs	92	91
Dry Hole Costs	40	11
Exploration and Development Expenditures	<u>3,342</u>	<u>3,839</u>
Asset Retirement Costs	27	32
<b>Total Exploration and Development Expenditures</b>	<u>3,369</u>	<u>3,871</u>
Other Property, Plant and Equipment	184	316
<b>Total Expenditures</b>	<u>\$ 3,553</u>	<u>\$ 4,187</u>

Exploration and development expenditures of \$3,342 million for the first six months of 2013 were \$497 million lower than the same period of 2012 due primarily to decreased drilling and facilities expenditures in the United States (\$430 million), Canada (\$53 million) and Argentina (\$23 million); and decreased leasehold acquisition expenditures in the United States (\$65 million) and Canada (\$21 million). These decreases were partially offset by increased drilling and facilities expenditures in Trinidad (\$49 million) and the United Kingdom (\$9 million). The exploration and development expenditures for the first six months of 2013 of \$3,342 million consist of \$2,941 million in development, \$376 million in exploration, \$22 million in capitalized interest and \$3 million in property acquisitions. The exploration and development expenditures for the first six months of 2012 of \$3,839 million consist of \$3,336 million in development, \$479 million in exploration and \$24 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to its operations, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

***Commodity Derivative Transactions.*** As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 22, 2013, EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk. EOG has not designated any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounts for financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as Gains on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income and Comprehensive Income. The related cash flow impact is reflected in Cash Flows from Operating Activities. In addition to financial transactions, from time to time EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.



**Commodity Derivative Contracts.** The total fair value of EOG's crude oil and natural gas derivative contracts was reflected on the Consolidated Balance Sheets at June 30, 2013 as a net asset of \$107 million. Presented below is a comprehensive summary of EOG's crude oil derivative contracts at August 6, 2013, with notional volumes expressed in barrels per day (Bbld) and prices expressed in dollars per barrel (\$/Bbl).

Crude Oil Derivative Contracts		
	Volume (Bbld)	Weighted Average Price (\$/Bbl)
<u>2013</u> <sup>(1)</sup>		
January 2013 (closed)	101,000	\$99.29
February 1, 2013 through April 30, 2013 (closed)	109,000	99.17
May 1, 2013 through June 30, 2013 (closed)	101,000	99.29
July 2013 (closed)	111,000	98.25
August 1, 2013 through September 30, 2013	126,000	98.80
October 1, 2013 through December 31, 2013	118,000	98.84
<u>2014</u> <sup>(2)</sup>		
January 1, 2014 through March 31, 2014	103,000	\$96.48
April 1, 2014 through June 30, 2014	93,000	96.47
July 1, 2014 through December 31, 2014	5,000	95.43

- (1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional three-month and six-month periods. Options covering a notional volume of 8,000 Bbld are exercisable on September 30, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 8,000 Bbld at an average price of \$98.11 per barrel for each month during the period October 1, 2013 through December 31, 2013. Options covering a notional volume of 64,000 Bbld are exercisable on December 31, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 64,000 Bbld at an average price of \$99.58 per barrel for each month during the period January 1, 2014 through June 30, 2014.
- (2) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional six-month and nine-month periods. Options covering a notional volume of 10,000 Bbld are exercisable on or about March 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 10,000 Bbld at an average price of \$96.60 per barrel for each month during the period April 1, 2014 through December 31, 2014. Options covering a notional volume of 93,000 Bbld are exercisable on or about June 30, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 93,000 Bbld at an average price of \$96.47 per barrel for each month during the period July 1, 2014 through December 31, 2014. Options covering a notional volume of 5,000 Bbld are exercisable on December 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 5,000 Bbld at an average price of \$95.43 per barrel for each month during the period January 1, 2015 through June 30, 2015.

Presented below is a comprehensive summary of EOG's natural gas derivative contracts at August 6, 2013, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu (\$/MMBtu).

Natural Gas Derivative Contracts		
	Volume (MMBtud)	Weighted Average Price (\$/MMBtu)
<u>2013</u> <sup>(1)</sup>		
January 1, 2013 through April 30, 2013 (closed)	150,000	\$4.79
May 1, 2013 through August 31, 2013 (closed)	200,000	4.72
September 1, 2013 through October 31, 2013	200,000	4.72
November 1, 2013 through December 31, 2013	150,000	4.79
<u>2014</u> <sup>(2)</sup>		
January 1, 2014 through December 31, 2014	170,000	\$4.54

- (1) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. For the period September 1, 2013 through October 31, 2013, if the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 200,000 MMBtud at an average price of \$4.72 per MMBtu for each month during that period. For the period November 1, 2013 through December 31, 2013, if the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 150,000 MMBtud at an average price of \$4.79 per MMBtu for each month during that period.
- (2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Additionally, in connection with certain natural gas derivative contracts settled in July 2012, counterparties retain an option of entering into derivative contracts at future dates. All such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 320,000 MMBtud at an average price of \$4.66 per MMBtu for each month during the period January 1, 2014 through December 31, 2014.

## Information Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, returns, budgets, reserves, levels of production and costs, statements regarding future commodity prices and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target," "goal," "may," "will," "should" and "believe" or the negative of those terms or other variations or comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production, generate income or cash flows or pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known, unknown or currently unforeseen risks, events or circumstances that may be outside EOG's control. Important factors that could cause EOG's actual results to differ materially from the expectations reflected in EOG's forward-looking statements include, among others:

- the timing and extent of changes in prices for, and demand for, crude oil and condensate, NGLs, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, and to produce reserves and achieve anticipated production levels from, its existing and future crude oil and natural gas exploration and development projects, given the risks and uncertainties and capital expenditure requirements inherent in drilling, completing and operating crude oil and natural gas wells and the potential for interruptions of development and production, whether involuntary or intentional as a result of market or other conditions;
- the extent to which EOG is successful in its efforts to market its crude oil, natural gas and related commodity production;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way, and EOG's ability to retain mineral licenses and leases;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;
- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- competition in the oil and gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation of production, gathering, processing, compression and transportation facilities;

- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- political conditions and developments around the world (such as political instability and armed conflict), including in the areas in which EOG operates;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts;
- physical, electronic and cyber security breaches; and
- the other factors described under Item 1A, "Risk Factors," on pages 16 through 23 of EOG's Annual Report on Form 10-K for the year ended December 31, 2012.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made, and EOG undertakes no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

## **PART I. FINANCIAL INFORMATION**

### **ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK EOG RESOURCES, INC.**

EOG's exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk is discussed in (i) the "Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" sections of "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity" on pages 42 through 47 of EOG's Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 22, 2013 (EOG's 2012 Annual Report); and (ii) Note 11, "Risk Management Activities," to EOG's Consolidated Financial Statements on pages F-25 through F-28 of EOG's 2012 Annual Report. There have been no material changes in this information. For additional information regarding EOG's financial commodity derivative contracts and physical commodity contracts, see (i) Note 12, "Risk Management Activities," to EOG's Consolidated Financial Statements in this Quarterly Report on Form 10-Q; (ii) "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Net Operating Revenues" in this Quarterly Report on Form 10-Q; and (iii) "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Commodity Derivative Transactions" in this Quarterly Report on Form 10-Q.

### **ITEM 4. CONTROLS AND PROCEDURES EOG RESOURCES, INC.**

***Disclosure Controls and Procedures.*** EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this Quarterly Report on Form 10-Q (Evaluation Date). Based on this evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of the Evaluation Date in ensuring that information that is required to be disclosed in the reports EOG files or furnishes under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission's rules and forms and (ii) accumulated and communicated to EOG's management, as appropriate, to allow timely decisions regarding required disclosure.

***Internal Control Over Financial Reporting.*** There were no changes in EOG's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act) that occurred during the quarterly period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

## PART II. OTHER INFORMATION

### EOG RESOURCES, INC.

#### ITEM 1. LEGAL PROCEEDINGS

See Part I, Item 1, Note 8 to Consolidated Financial Statements, which is incorporated herein by reference.

#### ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth, for the periods indicated, EOG's share repurchase activity:

Period	Total Number of Shares Purchased <sup>(1)</sup>	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under The Plans or Programs <sup>(2)</sup>
April 1, 2013 - April 30, 2013	48,588	\$ 115.86	-	6,386,200
May 1, 2013 - May 31, 2013	25,068	133.96	-	6,386,200
June 1, 2013 - June 30, 2013	8,490	131.83	-	6,386,200
Total	<u>82,146</u>	123.03	<u>-</u>	

(1) Represents shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock or restricted stock unit grants or (ii) in payment of the exercise price of employee stock options. These shares do not count against the 10 million aggregate share authorization by EOG's Board of Directors (Board) discussed below.

(2) In September 2001, the Board authorized the repurchase of up to 10 million shares of EOG's common stock. During the second quarter of 2013, EOG did not repurchase any shares under the Board-authorized repurchase program.

#### ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this report.

## ITEM 6. EXHIBITS

<u>Exhibit No.</u>	<u>Description</u>
3.1	- Bylaws, as amended and restated effective as of May 3, 2013 (incorporated by reference to Exhibit 4.2 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.1	- Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 2, 2013 (incorporated by reference to Exhibit 4.4 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.2	- Form of Restricted Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 4.5 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.3	- Form of Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 4.6 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.4	- Form of Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 4.7 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.5	- Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 4.8 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.6	- Form of Performance Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 4.9 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.7	- Form of Non-Employee Director Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 4.10 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
10.8	- Form of Non-Employee Director Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 4.11 to EOG's Registration Statement on Form S-8, filed May 3, 2013).
* 10.9	- Change of Control Agreement by and between EOG and Lloyd W. Helms, effective as of June 27, 2013.
* 31.1	- Section 302 Certification of Periodic Report of Principal Executive Officer.
* 31.2	- Section 302 Certification of Periodic Report of Principal Financial Officer.
* 32.1	- Section 906 Certification of Periodic Report of Principal Executive Officer.
* 32.2	- Section 906 Certification of Periodic Report of Principal Financial Officer.
* 95	- Mine Safety Disclosure Exhibit.

<b><u>Exhibit No.</u></b>	<b><u>Description</u></b>
* **101.INS	- XBRL Instance Document.
* **101.SCH	- XBRL Schema Document.
* **101.CAL	- XBRL Calculation Linkbase Document.
* **101.DEF	- XBRL Definition Linkbase Document.
* **101.LAB	- XBRL Label Linkbase Document.
* **101.PRE	- XBRL Presentation Linkbase Document.

\* Exhibits filed herewith

\*\* Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income and Comprehensive Income - Three Months Ended June 30, 2013 and 2012 and Six Months Ended June 30, 2013 and 2012, (ii) the Consolidated Balance Sheets - June 30, 2013 and December 31, 2012, (iii) the Consolidated Statements of Cash Flows - Six Months Ended June 30, 2013 and 2012 and (iv) Notes to Consolidated Financial Statements.



## SIGNATURES

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

EOG RESOURCES, INC.  
(Registrant)

Date: August 6, 2013

By: /s/ TIMOTHY K. DRIGGERS  
Timothy K. Driggers  
Vice President and Chief Financial Officer  
(Principal Financial Officer and Duly Authorized  
Officer)

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