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, 2011

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	**47-0684736**
(State or other jurisdiction of incorporation or organization)	(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	**Number of shares**
Common Stock, par value $0.01 per share	268,629,256 (as of July 29, 2011)

EOG RESOURCES, INC.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands, Except Per Share Data)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Net Operating Revenues				
Crude Oil and Condensate	$ 938,518	$ 455,808	$ 1,695,880	$ 861,970
Natural Gas Liquids	183,805	104,241	332,532	207,268
Natural Gas	599,993	553,354	1,183,912	1,230,336
Gains on Mark-to-Market Commodity Derivative Contracts	189,621	37,015	122,875	44,818
Gathering, Processing and Marketing	487,698	195,876	883,281	367,819
Gains on Asset Dispositions, Net	163,771	8,307	235,513	7,632
Other, Net	6,844	3,367	13,363	8,818
Total	2,570,250	1,357,968	4,467,356	2,728,661
Operating Expenses				
Lease and Well	216,695	160,734	431,784	326,726
Transportation Costs	101,965	94,345	199,598	183,056
Gathering and Processing Costs	17,716	13,220	36,912	28,881
Exploration Costs	41,238	50,131	92,147	101,328
Dry Hole Costs	1,676	19,318	24,627	42,395
Impairments	358,654	80,362	447,982	149,957
Marketing Costs	469,437	191,213	854,846	359,977
Depreciation, Depletion and Amortization	602,944	465,343	1,171,170	897,249
General and Administrative	67,406	64,737	137,443	125,160
Taxes Other Than Income	104,266	78,064	210,143	153,529
Total	1,981,997	1,217,467	3,606,652	2,368,258
Operating Income	588,253	140,501	860,704	360,403
Other Income (Expense), Net	6,224	(545)	9,828	2,138
Income Before Interest Expense and Income Taxes	594,477	139,956	870,532	362,541
Interest Expense, Net	51,253	29,897	101,586	55,325
Income Before Income Taxes	543,224	110,059	768,946	307,216
Income Tax Provision	247,650	50,187	339,399	129,329
Net Income	$ 295,574	$ 59,872	$ 429,547	$ 177,887
Net Income Per Share				
Basic	$ 1.11	$ 0.24	$ 1.65	$ 0.71
Diluted	$ 1.10	$ 0.24	$ 1.63	$ 0.70
Dividends Declared per Common Share	$ 0.160	$ 0.155	$ 0.320	$ 0.310
Average Number of Common Shares				
Basic	265,830	250,825	259,766	250,596
Diluted	269,332	254,503	263,363	254,206

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

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

	June 30, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,577,438	$ 788,853
Accounts Receivable, Net	1,279,740	1,113,279
Inventories	540,094	415,792
Assets from Price Risk Management Activities	109,225	48,153
Income Taxes Receivable	27,694	54,916
Deferred Income Taxes	-	9,260
Other	103,759	97,193
Total	3,637,950	2,527,446
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	31,588,860	29,263,809
Other Property, Plant and Equipment	1,871,497	1,733,073
Total Property, Plant and Equipment	33,460,357	30,996,882
Less: Accumulated Depreciation, Depletion and Amortization	(13,463,534)	(12,315,982)
Total Property, Plant and Equipment, Net	19,996,823	18,680,900
Other Assets	324,606	415,887
Total Assets	$ 23,959,379	$ 21,624,233
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 1,870,172	$ 1,664,944
Accrued Taxes Payable	148,645	82,168
Dividends Payable	42,976	38,962
Liabilities from Price Risk Management Activities	12,393	28,339
Deferred Income Taxes	50,180	41,703
Current Portion of Long-Term Debt	220,000	220,000
Other	131,872	143,983
Total	2,476,238	2,220,099
Long-Term Debt	5,006,251	5,003,341
Other Liabilities	718,696	667,455
Deferred Income Taxes	3,681,009	3,501,706
Commitments and Contingencies (Note 9)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 268,698,963 Shares Issued at June 30, 2011 and 254,223,521 Shares Issued at December 31, 2010	202,687	202,542
Additional Paid in Capital	2,181,157	729,992
Accumulated Other Comprehensive Income	492,880	440,071
Retained Earnings	9,213,356	8,870,179
Common Stock Held in Treasury, 143,309 Shares at June 30, 2011 and 146,186 Shares at December 31, 2010	(12,895)	(11,152)
Total Stockholders' Equity	12,077,185	10,231,632
Total Liabilities and Stockholders' Equity	$ 23,959,379	$ 21,624,233

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

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash Flows from Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 429,547	$ 177,887
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	1,171,170	897,249
Impairments	447,982	149,957
Stock-Based Compensation Expenses	53,427	44,953
Deferred Income Taxes	206,130	24,493
Gains on Asset Dispositions, Net	(235,513)	(7,632)
Other, Net	(834)	(1,252)
Dry Hole Costs	24,627	42,395
Mark-to-Market Commodity Derivative Contracts		
Total Gains	(122,875)	(44,818)
Realized Gains	31,285	38,827
Other, Net	13,268	8,454
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(165,300)	(39,275)
Inventories	(127,062)	(67,363)
Accounts Payable	189,250	254,878
Accrued Taxes Payable	94,311	(6,011)
Other Assets	(4,796)	(24,499)
Other Liabilities	(12,017)	(10,930)
Changes in Components of Working Capital Associated with Investing and Financing Activities	76,640	(135,973)
Net Cash Provided by Operating Activities	2,069,240	1,301,340
Investing Cash Flows		
Additions to Oil and Gas Properties	(3,122,567)	(2,288,270)
Additions to Other Property, Plant and Equipment	(340,140)	(115,661)
Proceeds from Sales of Assets	944,481	41,939
Changes in Components of Working Capital Associated with Investing Activities	(76,852)	135,693
Other, Net	-	(4,157)
Net Cash Used in Investing Activities	(2,595,078)	(2,230,456)
Financing Cash Flows		
Common Stock Sold	1,388,270	-
Long-Term Debt Borrowings	-	991,395
Long-Term Debt Repayments	-	(37,000)
Dividends Paid	(81,562)	(75,179)
Treasury Stock Purchased	(16,736)	(7,307)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	24,619	21,023
Debt Issuance Costs	-	(1,194)
Other, Net	212	280
Net Cash Provided by Financing Activities	1,314,803	892,018
Effect of Exchange Rate Changes on Cash	(380)	1,461
Increase (Decrease) in Cash and Cash Equivalents	788,585	(35,637)
Cash and Cash Equivalents at Beginning of Period	788,853	685,751
Cash and Cash Equivalents at End of Period	$ 1,577,438	$ 650,114

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, 2010, filed on February 24, 2011 (EOG's 2010 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, 2011 are not necessarily indicative of the results to be expected for the full year.

Recently Issued Accounting Standards and Developments. In June 2011, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) No. 2011-05 "Comprehensive Income (Topic 220): Presentation of Comprehensive Income." ASU No. 2011-05 is intended to increase the prominence of comprehensive income in the financial statements by requiring that an entity that reports items of comprehensive income do so in either one or two consecutive financial statements. A single statement should include total net income, the components of other comprehensive income, total other comprehensive income and total comprehensive income. In a two-statement approach, an entity will present total net income in the first statement and, in a statement immediately following the first, information about the components of total other comprehensive income and total comprehensive income. The provisions of ASU No. 2011-05 are effective for quarterly and annual fiscal periods beginning after December 15, 2011. Retroactive application is required.

2. Stock-Based Compensation

As more fully discussed in Note 6 to the Consolidated Financial Statements included in EOG's 2010 Annual Report, EOG maintains various stock-based compensation plans. Stock-based compensation expense is included in the Consolidated Statements of Income based upon the job function of the employee receiving the grants as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Lease and Well	$ 7.2	$ 6.0	$ 14.9	$ 12.3
Gathering and Processing Costs	0.2	0.3	0.4	0.3
Exploration Costs	5.5	5.3	11.6	10.8
General and Administrative	13.1	10.9	26.5	21.6
Total	$ 26.0	$ 22.5	$ 53.4	$ 45.0

The EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, as amended (2008 Plan), provides for grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards. At June 30, 2011, approximately 6.8 million common shares remained available for grant under the 2008 Plan. EOG's policy is to issue shares related to the 2008 Plan from previously authorized unissued shares.

Stock Options and Stock-Settled Stock Appreciation Rights and Employee Stock Purchase Plan. The fair value of all Employee Stock Purchase Plan (ESPP) grants is estimated using the Black-Scholes-Merton model. The fair value of stock option and SAR grants is estimated using the Hull-White II binomial option pricing model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $10.5 million and $9.3 million during the three months ended June 30, 2011 and 2010, respectively, and $19.9 million and $17.8 million during the six months ended June 30, 2011 and 2010, 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, 2011 and 2010 are as follows:

	Stock Options/SARs Six Months Ended June 30,		ESPP Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Weighted Average Fair Value of Grants	$ 36.57	$ 33.38	$ 21.55	$ 24.66
Expected Volatility	37.13%	38.05%	30.26%	34.78%
Risk-Free Interest Rate	1.12%	1.21%	0.18%	0.15%
Dividend Yield	0.6%	0.6%	0.6%	0.7%
Expected Life	5.4 yrs	5.0 yrs	0.5 yrs	0.5 yrs

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, 2011 and 2010 (stock options and SARs in thousands):

	Six Months Ended June 30, 2011			**Six Months Ended June 30, 2010**		
	Number of Stock Options/SARs		**Weighted Average Grant Price**	**Number of Stock Options/SARs**		**Weighted Average Grant Price**
Outstanding at January 1	8,445	$	64.49	8,335	$	57.08
Granted	80		110.36	91		103.36
Exercised (1)	(1,016)		51.11	(724)		40.72
Forfeited	(99)		87.22	(56)		79.22
Outstanding at June 30 (2)	7,410	$	66.51	7,646	$	59.02
Vested or Expected to Vest (3)	7,183	$	65.84	7,414	$	58.32
Exercisable at June 30 (4)	4,510	$	52.53	4,750	$	45.71

(1) The total intrinsic value of stock options/SARs exercised for the six months ended June 30, 2011 and 2010 was $59.9 million and $45.2 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, 2011 and 2010 was $283.6 million and $302.7 million, respectively. At June 30, 2011 and 2010, the weighted average remaining contractual life was 3.6 years and 3.8 years, respectively.
(3) The total intrinsic value of stock options/SARs vested or expected to vest at June 30, 2011 and 2010 was $279.8 million and $298.7 million, respectively. At June 30, 2011 and 2010, the weighted average remaining contractual life was 3.5 years and 3.8 years, respectively.
(4) The total intrinsic value of stock options/SARs exercisable at June 30, 2011 and 2010 was $235.5 million and $251.0 million, respectively. At June 30, 2011 and 2010, the weighted average remaining contractual life was 2.4 years and 2.9 years, respectively.

At June 30, 2011, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $70.9 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.4 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 $15.5 million and $13.2 million for the three months ended June 30, 2011 and 2010, respectively, and $33.5 million and $27.2 million for the six months ended June 30, 2011 and 2010, respectively.

The following table sets forth the restricted stock and restricted stock units transactions for the six-month periods ended June 30, 2011 and 2010 (shares and units in thousands):

	Six Months Ended June 30, 2011			Six Months Ended June 30, 2010		
	Number of Shares and Units		Weighted Average Grant Date Fair Value	Number of Shares and Units		Weighted Average Grant Date Fair Value
Outstanding at January 1	4,009	$	79.13	3,636	$	73.69
Granted	292		106.14	251		95.95
Released [(1)]	(213)		69.29	(206)		49.46
Forfeited	(97)		80.09	(44)		76.23
Outstanding at June 30 [(2)]	3,991	$	81.61	3,637	$	76.57

(1) The total intrinsic value of restricted stock and restricted stock units released for the six months ended June 30, 2011 and 2010 was $22.6 million and $20.4 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, 2011 and 2010 was $417.3 million and $357.7 million, respectively.

At June 30, 2011, unrecognized compensation expense related to restricted stock and restricted stock units totaled $136.2 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.5 years.

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, 2011 and 2010 (in thousands, except per share data):

	Three Months Ended June 30,				Six Months Ended June 30,			
		2011		2010		2011		2010
Numerator for Basic and Diluted Earnings Per Share -								
Net Income	$	295,574	$	59,872	$	429,547	$	177,887
Denominator for Basic Earnings Per Share -								
Weighted Average Shares		265,830		250,825		259,766		250,596
Potential Dilutive Common Shares -								
Stock Options/SARs		1,807		2,181		1,891		2,139
Restricted Stock and Restricted Stock Units		1,695		1,497		1,706		1,471
Denominator for Diluted Earnings Per Share -								
Adjusted Diluted Weighted Average Shares		269,332		254,503		263,363		254,206
Net Income Per Share								
Basic	$	1.11	$	0.24	$	1.65	$	0.71
Diluted	$	1.10	$	0.24	$	1.63	$	0.70

The diluted earnings per share calculation excludes stock options and SARs that were anti-dilutive. The excluded stock options and SARs totaled 0.2 million and 0.1 million shares for the three months ended June 30, 2011 and 2010, respectively, and 0.2 million and 0.1 million shares for the six months ended June 30, 2011 and 2010, 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, 2011 and 2010 (in thousands):

	Six Months Ended June 30,	
	2011	**2010**
Interest [(1)]	$ 81,557	$ 60,918
Income Taxes, Net of Refunds Received	$ 83,818	$ 129,850

(1) Net of capitalized interest of $30 million and $37 million for the six months ended June 30, 2011 and 2010, respectively.

EOG's accrued capital expenditures at June 30, 2011 and 2010 were $763 million and $527 million, respectively.

5. Comprehensive Income (Loss)

The following table presents the components of EOG's comprehensive income (loss) for the three-month and six-month periods ended June 30, 2011 and 2010 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Comprehensive Income (Loss)				
Net Income	$ 295,574	$ 59,872	$ 429,547	$ 177,887
Other Comprehensive Income (Loss)				
Foreign Currency Translation Adjustments	11,673	(91,256)	55,515	(29,088)
Foreign Currency Swap	(843)	842	(184)	5,390
Income Tax Related to Foreign Currency Swap	216	(215)	52	(1,443)
Interest Rate Swap Transaction	(5,713)	-	(4,109)	-
Income Tax Related to Interest Rate Swap Transaction	2,055	-	1,477	-
Other	28	26	58	52
Total	$ 302,990	$ (30,731)	$ 482,356	$ 152,798

6. Segment Information

Selected financial information by reportable segment is presented below for the three-month and six-month periods ended June 30, 2011 and 2010 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net Operating Revenues				
United States	$ 2,281,055	$ 1,123,161	$ 3,908,653	$ 2,243,862
Canada	140,575	113,560	256,538	253,599
Trinidad	141,454	114,782	287,342	217,996
Other International [(1)]	7,166	6,465	14,823	13,204
Total	$ 2,570,250	$ 1,357,968	$ 4,467,356	$ 2,728,661
Operating Income (Loss)				
United States	$ 804,653	$ 118,453	$ 1,014,539	$ 309,323
Canada	(299,980)	(42,778)	(319,416)	(55,220)
Trinidad	91,909	74,942	183,109	146,969
Other International [(1)]	(8,329)	(10,116)	(17,528)	(40,669)
Total	588,253	140,501	860,704	360,403
Reconciling Items				
Other Income (Expense), Net	6,224	(545)	9,828	2,138
Interest Expense, Net	51,253	29,897	101,586	55,325
Income Before Income Taxes	$ 543,224	$ 110,059	$ 768,946	$ 307,216

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

Total assets by reportable segment are presented below at June 30, 2011 and December 31, 2010 (in thousands):

	At June 30, 2011	At December 31, 2010
Total Assets		
United States	$ 20,309,529	$ 17,762,533
Canada	2,292,034	2,598,412
Trinidad	1,058,853	954,391
Other International [(1)]	298,963	308,897
Total	$ 23,959,379	$ 21,624,233

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

7. 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, 2011 and 2010 (in thousands):

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Carrying Amount at Beginning of Period	$ 498,288	$ 456,484
Liabilities Incurred	12,973	10,601
Liabilities Settled [1]	(38,748)	(8,168)
Accretion	12,268	12,086
Revisions	618	46
Foreign Currency Translations	2,834	(902)
Carrying Amount at End of Period	$ 488,233	$ 470,147
Current Portion	$ 22,959	$ 29,473
Noncurrent Portion	$ 465,274	$ 440,674

(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.

8. Exploratory Well Costs

EOG's net changes in capitalized exploratory well costs for the six-month period ended June 30, 2011 are presented below (in thousands):

	Six Months Ended June 30, 2011
Balance at December 31, 2010	$ 99,801
Additions Pending the Determination of Proved Reserves	21,923
Reclassifications to Proved Properties	(28,294)
Charged to Dry Hole Costs	(19,444)
Foreign Currency Translations	1,245
Balance at June 30, 2011	$ 75,231

The following table provides an aging of capitalized exploratory well costs at June 30, 2011 (in thousands, except well count):

		At June 30, 2011	
Capitalized exploratory well costs that have been capitalized for a period less than one year	$	10,945	
Capitalized exploratory well costs that have been capitalized for a period greater than one year		64,286	(1)
Total	$	75,231	
Number of exploratory wells that have been capitalized for a period greater than one year		4	

(1) Consists of costs related to a project in the Sichuan Basin, Sichuan Province, China ($27 million), an outside operated, offshore Central North Sea project in the United Kingdom (U.K.) ($22 million), an East Irish Sea project in the U.K. ($9 million), and a shale project in British Columbia, Canada (B.C.) ($6 million). The evaluation of the Sichuan Basin project is expected to be completed in early 2012. In the Central North Sea project, the operator and partners are currently negotiating processing and transportation terms with export infrastructure owners. The operator submitted a revised field development plan to the U.K. Department of Energy and Climate Change (DECC) and anticipates receiving approval of this plan during the first quarter of 2012. In the East Irish Sea project, EOG submitted its field development plan to the DECC during the first quarter of 2011 with regulatory approval expected by the end of 2011. In addition, EOG is in the process of designing and constructing the infrastructure for the project in anticipation of final regulatory approval. In the B.C. shale project, EOG drilled four additional wells during the first six months of 2011 to further evaluate the project. The related well completion activities are expected to commence in 2013.

9. 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.

10. Pension and Postretirement Benefits

EOG has a non-contributory defined contribution pension plan and a matched defined contribution savings plan in place for most of its employees in the United States, Canada, Trinidad and the United Kingdom, in addition to defined benefit pension plans covering certain employees of its Canadian and Trinidadian subsidiaries. For the six months ended June 30, 2011 and 2010, EOG's total costs recognized for these pension plans were $14 million and $13 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.

11. Long-Term Debt and Common Stock

Long-Term Debt. EOG utilizes commercial paper and short-term borrowings from uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper issuances or uncommitted credit facilities at June 30, 2011. The average borrowings outstanding under the commercial paper program were $3 million during the six months ended June 30, 2011. The weighted average interest rate for commercial paper borrowings for the six months ended June 30, 2011 was 0.32%.

EOG currently has two $1.0 billion unsecured Revolving Credit Agreements with domestic and foreign lenders. At June 30, 2011, there were no borrowings or letters of credit outstanding under either of these agreements. The first $1.0 billion unsecured Revolving Credit Agreement (2005 Agreement) matures on June 28, 2012. Advances under the 2005 Agreement accrue interest based, at EOG's option, on either the London Interbank Offering Rate plus an applicable margin (Eurodollar rate) or the base rate (as defined in the 2005 Agreement). At June 30, 2011, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2005 Agreement, would have been 0.38% and 3.25%, respectively.

The second $1.0 billion unsecured Revolving Credit Agreement (2010 Agreement) matures on September 10, 2013 (subject to EOG's option to extend, on up to two occasions, the term for successive one-year periods). Advances under the 2010 Agreement accrue interest based, at EOG's option, on either the Eurodollar rate or the base rate (as defined in the 2010 Agreement) plus an applicable margin. At June 30, 2011, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2010 Agreement, would have been 1.76% and 3.83%, respectively.

Fair Value of Debt. At both June 30, 2011 and December 31, 2010, EOG had outstanding $5,260 million aggregate principal amount of debt, which had estimated fair values of approximately $5,628 million and $5,602 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, upon interest rates available to EOG at the end of each respective period.

Common Stock. On March 7, 2011, EOG completed the sale of 13,570,000 shares of EOG common stock, par value $0.01 per share (Common Stock), at the public offering price of $105.50 per share. Net proceeds from the sale of the Common Stock were approximately $1,388 million after deducting the underwriting discount and offering expenses. Proceeds from the sale were used for general corporate purposes, including funding capital expenditures.

On February 17, 2011, the EOG Board of Directors increased the quarterly cash dividend on the Common Stock from the previous $0.155 per share to $0.16 per share effective with the dividend paid on April 29, 2011 to stockholders of record as of April 15, 2011.

12. Fair Value Measurements

As more fully discussed in Note 12 to the Consolidated Financial Statements included in EOG's 2010 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, 2011 and December 31, 2010 (in millions):

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
At June 30, 2011				
Financial Assets:				
Crude Oil and Natural Gas Price Swaps	$ -	$ 73	$ -	$ 73
Natural Gas Swaptions	-	57	-	57
Financial Liabilities:				
Foreign Currency Rate Swap	$ -	$ 62	$ -	$ 62
Interest Rate Swap	-	2	-	2
At December 31, 2010				
Financial Assets:				
Natural Gas Price Swaps	$ -	$ 62	$ -	$ 62
Natural Gas Swaptions	-	6	-	6
Interest Rate Swap	-	2	-	2
Financial Liabilities:				
Crude Oil Price Swaps and Natural Gas Basis Swaps	$ -	$ 29	$ -	$ 29
Foreign Currency Rate Swap	-	55	-	55

The estimated fair value of crude oil financial price swap contracts, natural gas financial price swap and basis swap contracts, natural gas swaption contracts and interest rate swap contracts 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.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on estimates of future retirement costs associated with oil and gas properties. 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 7.

Proved oil and gas properties with a carrying amount of $534 million were written down to their fair value of $174 million, resulting in a pretax impairment charge of $360 million for the six months ended June 30, 2011. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future natural gas and crude oil prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. In connection with certain first quarter 2011 impairments of proved oil and gas properties and other property, plant and equipment, EOG utilized an accepted offer from a third-party buyer.

13. Risk Management Activities

Commodity Price Risk. As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's 2010 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, collar and basis swap contracts, as a means to manage this price risk. In addition to financial transactions, 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. EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $190 million and $37 million for the three months ended June 30, 2011 and 2010, respectively, and $123 million and $45 million for the six months ended June 30, 2011 and 2010, respectively.

Financial Price Swap Contracts. Presented below is a comprehensive summary of EOG's crude oil and natural gas financial price swap contracts at June 30, 2011, with notional volumes expressed in barrels per day (Bbld) and in million British thermal units per day (MMBtud) and prices expressed in dollars per barrel ($/Bbl) and in dollars per million British thermal units ($/MMBtu), as applicable.

	Financial Price Swap Contracts			
	Crude Oil		Natural Gas	
	Volume (Bbld)	Weighted Average Price ($/Bbl)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2011 (1)				
January 2011 (closed)	17,000	$90.44	275,000	$5.19
February 2011 (closed)	18,000	90.69	425,000	5.09
March 2011 (closed)	20,000	91.82	425,000	5.09
April 2011 (closed)	24,000	93.61	475,000	5.03
May 2011 (closed)	24,000	93.61	650,000	4.90
June 2011 (closed)	30,000	97.02	650,000	4.90
July 1, 2011 through December 31, 2011 (2)	30,000	97.02	650,000	4.90
2012 (3)				
January 1, 2012 through December 31, 2012	9,000	$107.12	525,000	$5.44

(1) EOG has entered into natural gas financial price swap contracts which give counterparties the option of entering into price swap contracts at future dates. 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 financial price swap contracts will increase by 500,000 MMBtud at an average price of $4.73 per million British thermal units (MMBtu) for the period from August 1, 2011 through December 31, 2011.

(2) The crude oil contracts for July 2011 close on July 31, 2011. The natural gas contracts for July 2011 are closed.

(3) EOG has entered into natural gas financial price swap contracts which give counterparties the option of entering into price swap contracts at future dates. 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 financial price swap contracts will increase by 425,000 MMBtud at an average price of $5.44 per MMBtu for each month of 2012.

Subsequent to June 30, 2011, EOG entered into an additional crude oil financial price swap contract for the year 2012. See Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Commodity Derivative Transactions.

Foreign Currency Exchange Rate Risk. As more fully described in Note 2 to the Consolidated Financial Statements included in EOG's 2010 Annual Report, EOG is party to a foreign currency swap transaction with multiple banks to eliminate any exchange rate impacts that may result from the $150 million principal amount of notes issued by one of EOG's Canadian subsidiaries. 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 transaction was a reduction in Other Comprehensive Income (OCI) of $1 million and an increase in OCI of $1 million for the three months ended June 30, 2011 and 2010, respectively, and a reduction in OCI of $0.1 million and an increase in OCI of $4 million for the six months ended June 30, 2011 and 2010, respectively.

Interest Rate Derivatives. As more fully discussed in Note 2 to the Consolidated Financial Statements included in EOG's 2010 Annual Report, EOG is a party to an interest rate swap transaction to mitigate its exposure to volatility in interest rates related to EOG's $350 million principal amount of Floating Rate Senior Notes due 2014 issued on November 23, 2010. The interest rate swap has a notional amount of $350 million and a fair value at June 30, 2011 of $(2) million. EOG accounts for the interest rate swap transaction using the hedge accounting method. The after-tax net impact from the interest rate swap transaction was a decrease in OCI of $4 million and $3 million for the three and six months ended June 30, 2011, respectively.

The following table sets forth the amounts, on a gross basis, and classification of EOG's outstanding financial derivative financial instruments at June 30, 2011 and December 31, 2010. Certain amounts may be presented on a net basis in the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

		Fair Value at	
Description	**Location on Balance Sheet**	**June 30, 2011**	**December 31, 2010**
Asset Derivatives			
Crude oil and natural gas price swaps and natural gas swaptions -			
Current Portion	Assets from Price Risk Management Activities	$ 109	$ 51
Noncurrent Portion	Other Assets	$ 35	$ 18
Liability Derivatives			
Crude oil price swaps, natural gas price and basis swaps and natural gas swaptions -			
Current Portion	Liabilities from Price Risk Management Activities	$ 12	$ 30
Noncurrent Portion	Other Liabilities	$ 2	$ -
Foreign currency and interest rate swap - Noncurrent Portion	Other Liabilities	$ 64	$ 53

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 12). 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.

All of EOG's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDA) 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 12 for the aggregate fair value of all outstanding derivative instruments with credit-risk-related contingent features that are in a net liability position at June 30, 2011 and December 31, 2010. EOG had no collateral posted at either June 30, 2011 or December 31, 2010.

14. Acquisitions and Divestitures

In March 2011, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOGRC), purchased an additional 24.5% interest in the proposed Pacific Trail Pipelines (PTP) for $25.2 million. The PTP is intended to link western Canada's natural gas producing regions to the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia (Kitimat LNG Terminal). A portion of the purchase price ($15.3 million) was paid at closing with the remaining amount to be paid contingent on the decision to proceed with the construction of the Kitimat LNG Terminal. Additionally in March 2011, EOGRC and an affiliate of Apache Corporation (Apache), through a series of transactions, sold a portion of their interests in the Kitimat LNG Terminal and PTP to an affiliate of Encana Corporation (Encana). Subsequent to these transactions, ownership interests in both the Kitimat LNG Terminal and PTP are: Apache (operator) 40%, EOGRC 30% and Encana 30%. All future costs of the project will be paid by each party in proportion to its respective ownership percentage.

During the first half of 2011, EOG received proceeds of approximately $944 million from sales of producing properties and acreage and certain midstream assets, primarily in the Rocky Mountain area and Texas, and the sale of a portion of EOG's interest in the Kitimat LNG Terminal and PTP.

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 and China. 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 has proven a successful supplement to its base development and exploitation program in the United States and Canada. 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 natural gas production. EOG has placed an emphasis on applying its horizontal drilling expertise gained from its natural gas resources plays to unconventional crude oil reservoirs. In 2011, EOG has focused its efforts on developing its existing North American crude oil and condensate and natural gas liquids acreage and capturing additional North American horizontal crude oil plays. For the first half of 2011, crude oil and condensate and natural gas liquids production accounted for approximately 33% of total company production as compared to 26% for the comparable period in 2010. North American liquids production accounted for approximately 39% of total North American production during the first half of 2011 as compared to 30% for the comparable period in 2010. This liquids growth reflects production from the Eagle Ford Shale Play near San Antonio, Texas, and increasing amounts of crude oil and condensate and natural gas liquids production in the Fort Worth Basin Barnett Shale area and in the Colorado Niobrara. Based on current trends, EOG expects its 2011 crude oil and condensate and natural gas liquids production to continue to increase both in total and as a percentage of total company production as compared to 2010. In addition, EOG continues to evaluate certain potential liquids-rich exploration and development prospects. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada. In order to create market diversification for its growing crude oil production, EOG is expanding its crude-by-rail system to deliver crude oil and condensate to St. James, Louisiana, thereby adding the option of receiving a Light Louisiana Sweet crude price. In addition, to further reduce well completion costs, EOG expects to begin using sand from its Wisconsin processing facilities in late 2011.

In March 2011, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOGRC), purchased an additional 24.5% interest in the proposed Pacific Trail Pipelines (PTP) for $25.2 million. The PTP is intended to link western Canada's natural gas producing regions to the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia (Kitimat LNG Terminal). A portion of the purchase price ($15.3 million) was paid at closing with the remaining amount to be paid contingent on the decision to proceed with the construction of the Kitimat LNG Terminal. Additionally in March 2011, EOGRC and an affiliate of Apache Corporation (Apache), through a series of transactions, sold a portion of their interests in the Kitimat LNG Terminal and PTP to an affiliate of Encana Corporation (Encana). Subsequent to these transactions, ownership interests in both the Kitimat LNG Terminal and PTP are: Apache (operator) 40%, EOGRC 30% and Encana 30%. All future costs of the project will be paid by each party in proportion to its respective ownership percentage. In the first quarter of 2011, EOGRC and Apache awarded a front-end engineering and design contract to a global engineering company with the final report expected in early 2012.

International. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium (SECC) Block, Modified U(a) Block and Modified U(b) Block, as well as the Pelican Field, have been developed and are producing crude oil and condensate and natural gas. During the first half of 2011, EOG drilled six development wells in the Toucan Field on Block 4(a) and expects to complete these wells in the fourth quarter of 2011 with first production expected in 2012. In the United Kingdom, EOG continues to make progress in field development plans for its East Irish Sea Conwy/Corfe crude oil discovery and its Central North Sea Columbus natural gas discovery. During 2011, EOG signed two exploration contracts and one farm-in agreement covering approximately 100,000 net acres in the Neuquen Basin in Neuquen Province, Argentina.

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 with large shale plays where 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 30% at June 30, 2011 and 34% at December 31, 2010. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

On March 7, 2011, EOG completed the sale of 13,570,000 shares of EOG common stock, par value $0.01 per share (Common Stock), at the public offering price of $105.50 per share. Net proceeds from the sale of the Common Stock were approximately $1.39 billion after deducting the underwriting discount and offering expenses. Proceeds from the sale were used for general corporate purposes, including funding capital expenditures. During the first half of 2011, EOG funded $3.6 billion in exploration and development and other property, plant and equipment expenditures and paid $82 million in dividends to common stockholders, primarily by utilizing cash on hand, cash provided from its operating activities, proceeds from the Common Stock sold and proceeds from asset sales.

The total anticipated 2011 capital expenditures are estimated to range from $6.8 billion to $7.0 billion, excluding acquisitions. The majority of 2011 expenditures will be focused on United States and Canada crude oil drilling activity and, to a lesser extent, natural gas drilling activity in the Haynesville, Marcellus and British Columbia Horn River Basin plays to hold acreage. EOG expects capital expenditures to be greater than cash flow from operating activities for 2011. Along with the sale of Common Stock discussed above, EOG's business plan includes selling certain non-core natural gas assets in 2011 to cover the anticipated shortfall. In the first half of 2011, proceeds of approximately $944 million were received from sales of producing properties and acreage and certain midstream assets, primarily in the Rocky Mountain area and Texas, and the sale of a portion of EOG's interest in the Kitimat LNG Terminal and PTP. 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 revolving credit facilities 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, 2011 and 2010 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, 2011 vs. Three Months Ended June 30, 2010

Net Operating Revenues. During the second quarter of 2011, net operating revenues increased $1,212 million, or 89%, to $2,570 million from $1,358 million for the same period of 2010. 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 2011 increased $609 million, or 55%, to $1,722 million from $1,113 million for the same period of 2010. During the second quarter of 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $190 million compared to net gains of $37 million for the same period of 2010. 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 2011 increased $292 million, or 149%, to $488 million from $196 million for the same period of 2010. Gains on asset dispositions, net, of $164 million for the second quarter of 2011 primarily consist of gains on asset dispositions in the Rocky Mountain area and Texas.

Wellhead volume and price statistics for the three-month periods ended June 30, 2011 and 2010 were as follows:

	Three Months Ended June 30,	
	2011	**2010**
Crude Oil and Condensate Volumes (MBbld) (1)		
United States	92.3	57.6
Canada	8.8	6.6
Trinidad	3.3	5.4
Other International (2)	0.1	0.1
Total	104.5	69.7
Average Crude Oil and Condensate Prices ($/Bbl) (3)		
United States	$ 99.50	$ 73.18
Canada	102.65	71.63
Trinidad	99.49	68.90
Other International (2)	101.52	73.21
Composite	99.77	72.69
Natural Gas Liquids Volumes (MBbld) (1)		
United States	38.4	27.5
Canada	0.7	0.9
Total	39.1	28.4
Average Natural Gas Liquids Prices ($/Bbl) (3)		
United States	$ 51.50	$ 40.31
Canada	60.39	42.55
Composite	51.65	40.38
Natural Gas Volumes (MMcfd) (1)		
United States	1,114	1,069
Canada	139	204
Trinidad	349	341
Other International (2)	13	15
Total	1,615	1,629
Average Natural Gas Prices ($/Mcf) (3)		
United States	$ 4.24	$ 4.12
Canada	4.16	3.60
Trinidad	3.51	2.58
Other International (2)	5.61	4.27
Composite	4.08	3.73
Crude Oil Equivalent Volumes (MBoed) (4)		
United States	316.4	263.2
Canada	32.6	41.5
Trinidad	61.4	62.2
Other International (2)	2.2	2.7
Total	412.6	369.6
Total MMBoe (4)	37.5	33.6

(1) Thousand barrels per day or million cubic feet per day, as applicable.
(2) Other International includes EOG's United Kingdom and China 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 2011 increased $483 million, or 106%, to $939 million from $456 million for the same period of 2010, due to an increase of 35 MBbld, or 50%, in wellhead crude oil and condensate deliveries ($228 million) and a higher composite average wellhead crude oil and condensate price ($255 million). The increase in deliveries primarily reflects increased production in Texas (30 MBbld) and Colorado (4 MBbld). Production increases in Texas were the result of increased production from the Eagle Ford and Fort Worth Basin Barnett Combo plays. EOG's composite average wellhead crude oil and condensate price for the second quarter of 2011 increased 37% to $99.77 per barrel compared to $72.69 per barrel for the same period of 2010.

Natural gas liquids revenues for the second quarter of 2011 increased $80 million, or 76%, to $184 million from $104 million for the same period of 2010, due to an increase of 11 MBbld, or 38%, in natural gas liquids deliveries ($40 million) and a higher composite average natural gas liquids price ($40 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale and Rocky Mountain areas. EOG's composite average natural gas liquids price for the second quarter of 2011 increased 28% to $51.65 per barrel compared to $40.38 per barrel for the same period of 2010.

Wellhead natural gas revenues for the second quarter of 2011 increased $47 million, or 8%, to $600 million from $553 million for the same period of 2010. The increase was due to a higher composite average wellhead natural gas price ($52 million), partially offset by a decrease in natural gas deliveries ($5 million). EOG's composite average wellhead natural gas price for the second quarter of 2011 increased 9% to $4.08 per Mcf compared to $3.73 per Mcf for the same period of 2010.

Natural gas deliveries for the second quarter of 2011 decreased 14 MMcfd, or 1%, to 1,615 MMcfd from 1,629 MMcfd for the same period of 2010. The decrease was primarily due to lower production in Canada (65 MMcfd), partially offset by increased production in the United States (45 MMcfd) and Trinidad (8 MMcfd). The decreased production in Canada primarily reflects sales of certain shallow natural gas assets in the fourth quarter of 2010, partially offset by increased production from the Horn River Basin area. The increase in the United States was primarily attributable to increased production in Texas (65 MMcfd), Pennsylvania (20 MMcfd) and Louisiana (23 MMcfd), partially offset by decreased production in the Rocky Mountain area (32 MMcfd), Mississippi (17 MMcfd) and New Mexico (7 MMcfd). The increase in Trinidad was primarily attributable to an increase in contractual deliveries.

During the second quarter of 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $190 million compared to net gains of $37 million for the same period of 2010. During the second quarter of 2011, the net cash inflow related to settled crude oil and natural gas financial price swap contracts was $6 million compared to the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts of $16 million for the same period of 2010.

Gathering, processing and marketing revenues represent 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 three months and six months ended June 30, 2011 and 2010, gathering, processing and marketing revenues were primarily related to sales of third-party crude oil and natural gas. The purchase and sale 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 2011, gathering, processing and marketing revenues and marketing costs increased primarily as a result of increased crude oil and natural gas marketing activities. Gathering, processing and marketing revenues less marketing costs for the second quarter of 2011 increased to $18 million from $5 million for the same period of 2010 due primarily to increased activity and higher margins from crude oil and natural gas marketing activities.

Operating and Other Expenses. For the second quarter of 2011, operating expenses of $1,982 million were $765 million higher than the $1,217 million incurred in the second quarter of 2010. The following table presents the costs per barrel of oil equivalent (Boe) for the three-month periods ended June 30, 2011 and 2010:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	
Lease and Well	$ 5.79	$ 4.79	
Transportation Costs	2.72	2.81	
Depreciation, Depletion and Amortization (DD&A) -			
Oil and Gas Properties	15.25	13.08	(1)
Other Property, Plant and Equipment	0.85	0.86	
General and Administrative (G&A)	1.80	1.93	
Interest Expense, Net	1.37	0.89	
Total (2)	$ 27.78	$ 24.36	

(1) The 2010 amount excludes the change in the estimated fair value of a contingent consideration liability relating to the acquisition of certain unproved acreage of $2 million, or $0.07 per Boe.

(2) 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, and interest expense, net for the three months ended June 30, 2011 compared to the same period of 2010 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 EOG's 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 $217 million for the second quarter of 2011 increased $56 million from $161 million for the same prior year period primarily due to higher operating and maintenance costs in the United States ($40 million), increased lease and well administrative expenses ($9 million) and unfavorable changes in the Canadian exchange rate ($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 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, fuel costs, transportation fees and costs associated with crude-by-rail operations.

Transportation costs of $102 million for the second quarter of 2011 increased $8 million from $94 million for the same prior year period primarily due to increased transportation costs in the Upper Gulf Coast area ($6 million), the San Antonio area ($5 million) and the Fort Worth Basin Barnett Shale area ($2 million), partially offset by decreased transportation costs in the Rocky Mountain area ($2 million). The increase in transportation costs primarily reflects increased volumes transported to downstream markets.

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 field 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 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 calculated using the straight-line depreciation method over the useful lives of the assets. Other property, plant and equipment consists of gathering and processing assets, compressors, crude-by-rail assets, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

DD&A expenses for the second quarter of 2011 increased $138 million to $603 million from $465 million for the same prior year period. DD&A expenses associated with oil and gas properties for the second quarter of 2011 were $135 million higher than the same prior year period primarily due to higher unit rates in the United States ($72 million) and Trinidad ($14 million) and as a result of increased production in the United States ($66 million), and unfavorable changes in the Canadian exchange rate ($4 million), partially offset by decreased production ($18 million) and lower unit rates ($2 million) in Canada.

DD&A expenses associated with other property, plant and equipment for the second quarter of 2011 were $3 million higher than the same prior year period primarily due to gathering and processing assets placed in service in the San Antonio area.

Interest expense, net, of $51 million for the second quarter of 2011 increased $21 million compared to the same prior year period primarily due to a higher average debt balance ($17 million) and lower capitalized interest ($4 million).

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 $18 million for the second quarter of 2011 compared to $13 million for the same prior year period. The increase primarily reflects increased activities in the United States due primarily to increased activity in the Fort Worth Basin Barnett Shale area.

Exploration costs of $41 million for the second quarter of 2011 decreased $9 million from $50 million for the same prior year period primarily due to decreased geological and geophysical expenditures in the United States.

Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties. 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 producing field 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 discounting the future cash flows at an appropriate risk-adjusted discount rate. For certain natural gas assets held for sale, EOG utilizes accepted bids as the basis for determining fair value.

Impairments of $359 million for the second quarter of 2011 were $278 million higher than impairments for the same prior year period primarily due to increased impairments of proved properties in Canada ($285 million) and changes in the Canadian exchange rate ($19 million), partially offset by decreased amortization of unproved property costs in the United States ($13 million) and decreased impairments of proved properties in the United States ($11 million). EOG recorded impairments of proved properties of $312 million and $20 million for the second quarter of 2011 and 2010, respectively. Impairments of proved properties in the second quarter of 2011 relate primarily to certain Canadian shallow natural gas assets.

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 2011 increased $26 million to $104 million (6.1% of wellhead revenues) compared to $78 million (7.0% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to increased severance/production taxes as a result of increased wellhead revenues in the United States ($29 million) and higher ad valorem/property taxes in the United States ($3 million), partially offset by an increase in credits available to EOG in 2011 for Texas high-cost gas severance tax rate reductions ($3 million) and lower ad valorem/property taxes in Canada as a result of asset dispositions during 2010 ($2 million).

Other income (expense), net for the second quarter of 2011 increased $7 million from the same prior year period. The increase was primarily due to higher equity income from ammonia plants in Trinidad ($3 million) and an increase in foreign currency transaction gains ($2 million).

Income tax provision of $248 million for the second quarter of 2011 increased $198 million compared to the same prior year period due primarily to taxes associated with increased pretax earnings. The effective tax rate of 46% for the second quarter of 2011 was unchanged from the prior year period. The effective tax rate for the second quarter of 2011 exceeded the United States federal statutory tax rate (35%) due to losses related to the Canadian shallow natural gas asset impairment (27% statutory tax rate) and earnings in Trinidad (55% statutory tax rate).

Six Months Ended June 30, 2011 vs. Six Months Ended June 30, 2010

Net Operating Revenues. During the first six months of 2011, net operating revenues increased $1,738 million, or 64%, to $4,467 million from $2,729 million for the same period of 2010. Total wellhead revenues for the first six months of 2011 increased $912 million, or 40%, to $3,212 million from $2,300 million for the same period of 2010. During the first six months of 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $123 million compared to net gains of $45 million for the same period of 2010. Gathering, processing and marketing revenues for the first six months of 2011 increased $515 million, or 140%, to $883 million from $368 million for the same period of 2010. Gains on asset dispositions, net, of $236 million for the first six months of 2011 primarily consist of gains on asset dispositions in the Rocky Mountain area and Texas.

Wellhead volume and price statistics for the six-month periods ended June 30, 2011 and 2010 were as follows:

	Six Months Ended June 30, 2011		Six Months Ended June 30, 2010	
Crude Oil and Condensate Volumes (MBbld)				
United States		86.8		55.9
Canada		8.6		6.2
Trinidad		3.9		4.6
Other International		0.1		0.1
Total		99.4		66.8
Average Crude Oil and Condensate Prices ($/Bbl) [1]				
United States	$	94.05	$	73.23
Canada		93.65		72.39
Trinidad		92.33		67.89
Other International		93.67		72.18
Composite		93.95		72.77
Natural Gas Liquids Volumes (MBbld)				
United States		36.5		25.6
Canada		0.8		0.9
Total		37.3		26.5
Average Natural Gas Liquids Prices ($/Bbl)				
United States	$	49.21	$	43.23
Canada		52.77		44.09
Composite		49.29		43.25
Natural Gas Volumes (MMcfd)				
United States		1,124		1,055
Canada		141		208
Trinidad		367		346
Other International		13		16
Total		1,645		1,625
Average Natural Gas Prices ($/Mcf) [1]				
United States	$	4.17	$	4.67
Canada		3.91		4.42
Trinidad		3.35		2.54
Other International		5.62		4.27
Composite		3.98		4.18
Crude Oil Equivalent Volumes (MBoed)				
United States		310.7		257.5
Canada		32.9		41.7
Trinidad		65.0		62.3
Other International		2.3		2.7
Total		410.9		364.2
Total MMBoe		74.4		65.9

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

Wellhead crude oil and condensate revenues for the first six months of 2011 increased $834 million, or 97%, to $1,696 million from $862 million for the same period of 2010, due to an increase of 33 MBbld, or 49%, in wellhead crude oil and condensate deliveries ($452 million) and a higher composite average wellhead crude oil and condensate price ($382 million). The increase in deliveries primarily reflects increased production in Texas (24 MBbld) and Colorado (4 MBbld). Production increases in Texas were the result of increased production from the Eagle Ford and Fort Worth Basin Barnett Combo plays. EOG's composite average wellhead crude oil and condensate price for the first six months of 2011 increased 29% to $93.95 per barrel compared to $72.77 per barrel for the same period of 2010.

Natural gas liquids revenues for the first six months of 2011 increased $126 million, or 60%, to $333 million from $207 million for the same period of 2010, due to an increase of 11 MBbld, or 41%, in natural gas liquids deliveries ($85 million) and a higher composite average natural gas liquids price ($41 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale and Rocky Mountain areas. EOG's composite average natural gas liquids price for the first six months of 2011 increased 14% to $49.29 per barrel compared to $43.25 per barrel for the same period of 2010.

Wellhead natural gas revenues for the first six months of 2011 decreased $46 million, or 4%, to $1,184 million from $1,230 million for the same period of 2010. The decrease was due to a lower composite average wellhead natural gas price ($61 million), partially offset by an increase in natural gas deliveries ($15 million). EOG's composite average wellhead natural gas price for the first six months of 2011 decreased 5% to $3.98 per Mcf compared to $4.18 per Mcf for the same period of 2010.

Natural gas deliveries for the first six months of 2011 increased 20 MMcfd, or 1%, to 1,645 MMcfd from 1,625 MMcfd for the same period of 2010. The increase was primarily due to increased production in the United States (69 MMcfd) and Trinidad (21 MMcfd), partially offset by lower production in Canada (67 MMcfd). The increase in the United States was primarily attributable to increased production in Texas (95 MMcfd), Pennsylvania (17 MMcfd) and Louisiana (12 MMcfd), partially offset by decreased production in the Rocky Mountain area (29 MMcfd), Mississippi (14 MMcfd) and New Mexico (5 MMcfd). The increase in Trinidad was primarily attributable to an increase in contractual deliveries. The decreased production in Canada primarily reflects sales of certain shallow natural gas assets in the fourth quarter of 2010, partially offset by increased production from the Horn River Basin area.

During the first six months of 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $123 million compared to net gains of $45 million for the same period of 2010. During the first six months of 2011, the net cash inflow related to settled crude oil and natural gas financial price swap contracts and natural gas basis swap contracts was $31 million compared to the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts of $39 million for the same period of 2010.

During the first six months of 2011, gathering, processing and marketing revenues and marketing costs increased primarily as a result of increased crude oil and natural gas marketing activities. Gathering, processing and marketing revenues less marketing costs for the first six months of 2011 totaled $28 million compared to $8 million for the same period of 2010, primarily as a result of increased activity and higher margins from crude oil and natural gas marketing activities.

Operating and Other Expenses. For the first six months of 2011, operating expenses of $3,607 million were $1,239 million higher than the $2,368 million incurred in the same period of 2010. The following table presents the costs per Boe for the six-month periods ended June 30, 2011 and 2010:

	Six Months Ended June 30,	
	2011	**2010**
Lease and Well	$ 5.80	$ 4.98
Transportation Costs	2.68	2.79
DD&A -		
Oil and Gas Properties (1)	14.91	13.10
Other Property, Plant and Equipment	0.84	0.86
G&A	1.85	1.91
Interest Expense, Net	1.36	0.84
Total (2)	$ 27.44	$ 24.48

(1) The 2011 and 2010 amounts exclude the change in the estimated fair value of a contingent consideration liability relating to the acquisition of certain unproved acreage of $1 million, or $0.01 per Boe, and $19 million, or $0.29 per Boe, respectively.

(2) 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, 2011 compared to the same period of 2010 are set forth below.

Lease and well expenses of $432 million for the first six months of 2011 increased $105 million from $327 million for the same prior year period primarily due to higher operating and maintenance costs in the United States ($82 million) and higher lease and well administrative expenses ($18 million).

Transportation costs of $200 million for the first six months of 2011 increased $17 million from $183 million for the same prior year period primarily due to increased transportation costs in the Upper Gulf Coast area ($13 million), the San Antonio area ($5 million) and the Fort Worth Basin Barnett Shale area ($5 million), partially offset by decreased transportation costs in Canada ($2 million) and the South Texas area ($2 million). The increase in transportation costs primarily reflects increased volumes transported to downstream markets.

DD&A expenses for the first six months of 2011 increased $274 million to $1,171 million from $897 million for the same prior year period. DD&A expenses associated with oil and gas properties for the first six months of 2011 were $268 million higher than the same prior year period primarily as a result of increased production in the United States ($133 million), higher unit rates in the United States ($129 million) and Trinidad ($32 million) and unfavorable changes in the Canadian exchange rate ($8 million), partially offset by decreased production in Canada ($35 million).

DD&A expenses associated with other property, plant and equipment for the first six months of 2011 were $6 million higher than the same prior year period primarily due to gathering and processing assets placed in service in the Rocky Mountain area ($3 million) and the San Antonio area ($2 million).

G&A expenses of $137 million for the first six months of 2011 increased $12 million compared to the same prior year period primarily due to higher employee-related costs.

Interest expense, net, of $102 million for the first six months of 2011 increased $47 million from $55 million for the same prior year period primarily due to a higher average debt balance ($39 million) and lower capitalized interest ($7 million).

Gathering and processing costs for the first six months of 2011 increased $8 million to $37 million compared to the same prior year period primarily due to increased activities in the United States ($5 million), due primarily to increased activity in the Fort Worth Basin Barnett Shale area, and Canada ($3 million).

Exploration costs of $92 million for the first six months of 2011 decreased $9 million from $101 million for the same prior year period primarily due to decreased geological and geophysical expenditures in the United States.

Impairments of $448 million for the first six months of 2011 were $298 million higher than impairments for the same prior year period primarily due to increased impairments of proved properties in Canada ($284 million) and in the United States ($27 million) and changes in the Canadian exchange rate ($19 million), partially offset by decreased amortization of unproved property costs in the United States ($30 million). EOG recorded impairments of proved properties of $360 million and $31 million for the first six months of 2011 and 2010, respectively. Impairments of proved properties in the first six months of 2011 relate primarily to certain Canadian shallow natural gas assets.

Taxes other than income for the first six months of 2011 increased $56 million to $210 million (6.5% of wellhead revenues) from $154 million (6.7% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to increased severance/production taxes primarily as a result of increased wellhead revenues in the United States ($49 million), Trinidad ($2 million) and Canada ($2 million) and higher ad valorem/property taxes in the United States ($4 million), partially offset by lower ad valorem/property taxes in Canada as a result of property dispositions during 2010 ($3 million).

Other income (expense), net was $10 million for the first six months of 2011 compared to $2 million for the same prior year period. The increase of $8 million was primarily due to an increase in foreign currency transaction gains ($7 million) and higher equity income from EOG's investment in ammonia plants in Trinidad ($2 million).

Income tax provision of $339 million for the first six months of 2011 increased $210 million compared to the same prior year period due primarily to taxes associated with increased pretax earnings. The effective tax rate for the first six months of 2011 increased to 44% from 42% in the comparable prior year period. The effective tax rate for the first six months of 2011 exceeded the United States federal statutory tax rate (35%) due to losses related to the Canadian shallow natural gas asset impairment (27% statutory tax rate) and earnings in Trinidad (55% statutory tax rate).

Capital Resources and Liquidity

Cash Flow. The primary sources of cash for EOG during the six months ended June 30, 2011 were funds generated from operations, net proceeds from the sale of Common Stock previously discussed, 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; and dividend payments to stockholders. During the first six months of 2011, EOG's cash balance increased $788 million to $1,577 million from $789 million at December 31, 2010.

Net cash provided by operating activities of $2,069 million for the first six months of 2011 increased $768 million compared to the same period of 2010 primarily reflecting an increase in wellhead revenues ($913 million) and a decrease in net cash paid for income taxes ($46 million), partially offset by an increase in cash operating expenses ($179 million), unfavorable changes in working capital and other assets and liabilities ($32 million), an increase in net cash paid for interest expense ($21 million) and an unfavorable change in net cash flow from the settlement of financial commodity derivative contracts ($8 million).

Net cash used in investing activities of $2,595 million for the first six months of 2011 increased by $365 million compared to the same period of 2010 due primarily to an increase in additions to oil and gas properties ($834 million); an increase in additions to other property, plant and equipment ($224 million); and unfavorable changes in working capital associated with investing activities ($213 million); partially offset by an increase in proceeds from sales of assets ($903 million).

Net cash provided by financing activities of $1,315 million for the first six months of 2011 included net proceeds from the sale of Common Stock ($1,388 million) and proceeds from stock options exercised and employee stock purchase plan activity ($25 million). Cash used in financing activities for the first six months of 2011 included cash dividend payments ($82 million) and the purchase of treasury stock in connection with stock compensation plans ($17 million). Net cash provided by financing activities of $892 million for the first six months of 2010 included proceeds from the issuances of long-term debt ($991 million) and proceeds from stock options exercised and employee stock purchase plan activity ($21 million). Cash used in financing activities for the first six months of 2010 included cash dividend payments ($75 million), the repayment of long-term debt ($37 million) and the purchase of treasury stock in connection with stock compensation plans ($7 million).

Total Expenditures. For 2011, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $6.8 billion to $7.0 billion, excluding acquisitions. The table below sets forth components of total expenditures for the six-month periods ended June 30, 2011 and 2010 (in millions):

	Six Months Ended June 30,	
	2011	**2010**
Expenditure Category		
Capital		
Drilling and Facilities	$ 2,930	$ 1,934
Leasehold Acquisitions	133	257
Property Acquisitions	4	21
Capitalized Interest	30	37
Subtotal	3,097	2,249
Exploration Costs	92	101
Dry Hole Costs	25	42
Exploration and Development Expenditures	3,214	2,392
Asset Retirement Costs	15	13
Total Exploration and Development Expenditures	3,229	2,405
Other Property, Plant and Equipment	340	116
Total Expenditures	$ 3,569	$ 2,521

Exploration and development expenditures of $3,214 million for the first six months of 2011 were $822 million higher than the same period of 2010 due primarily to increased drilling and facilities expenditures in the United States ($1,001 million), the United Kingdom ($18 million) and Trinidad ($10 million); changes in the foreign currency exchange rate in Canada ($9 million) and increased dry hole costs in the United States ($9 million); partially offset by decreased leasehold acquisitions expenditures in the United States ($113 million) and Canada ($11 million); decreased drilling and facilities expenditures in China ($28 million) and Canada ($15 million); decreased dry hole costs in the United Kingdom ($22 million) and Trinidad ($5 million); decreased property acquisitions expenditures in the United States ($17 million); decreased capitalized interest in the United States ($7 million) and decreased exploration geological and geophysical expenditures in the United States ($9 million). The exploration and development expenditures for the first six months of 2011 of $3,214 million include $2,902 million in development, $278 million in exploration, $30 million in capitalized interest and $4 million in property acquisitions. The exploration and development expenditures for the first six months of 2010 of $2,392 million include $1,743 million in development, $591 million in exploration, $37 million in capitalized interest and $21 million in property acquisitions.

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 operations in the United States, Canada, Trinidad, the United Kingdom and China, 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, 2010, filed on February 24, 2011, 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, 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. The related cash flow impact is reflected as Cash Flows from Operating Activities. In addition to financial transactions, 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.

Financial Price Swap Contracts. The total fair value of EOG's crude oil and natural gas financial price swap contracts was reflected on the Consolidated Balance Sheets at June 30, 2011 as a net asset of $24 million and a net asset of $106 million, respectively. Presented below is a comprehensive summary of EOG's crude oil and natural gas financial price swap contracts at August 4, 2011, with notional volumes expressed in barrels per day (Bbld) and in million British thermal units per day (MMBtud) and prices expressed in dollars per barrel ($/Bbl) and in dollars per million British thermal units ($/MMBtu), as applicable.

	Financial Price Swap Contracts			
	Crude Oil		Natural Gas	
	Volume (Bbld)	Weighted Average Price ($/Bbl)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2011 (1)				
January 2011 (closed)	17,000	$90.44	275,000	$5.19
February 2011 (closed)	18,000	90.69	425,000	5.09
March 2011 (closed)	20,000	91.82	425,000	5.09
April 2011 (closed)	24,000	93.61	475,000	5.03
May 2011 (closed)	24,000	93.61	650,000	4.90
June 1, 2011 through July 31, 2011 (closed)	30,000	97.02	650,000	4.90
August 2011 (2)	30,000	97.02	650,000	4.90
September 1, 2011 through December 31, 2011	30,000	97.02	650,000	4.90
2012 (3)				
January 1, 2012 through December 31, 2012	11,000	$106.37	525,000	$5.44

(1) EOG has entered into natural gas financial price swap contracts which give counterparties the option of entering into price swap contracts at future dates. 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 financial price swap contracts will increase by 500,000 MMBtud at an average price of $4.73 per million British thermal units (MMBtu) for the period from September 1, 2011 through December 31, 2011.

(2) The crude oil contracts for August 2011 will close on August 31, 2011. The natural gas contracts for August 2011 are closed.

(3) EOG has entered into natural gas financial price swap contracts which give counterparties the option of entering into price swap contracts at future dates. 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 financial price swap contracts will increase by 425,000 MMBtud at an average price of $5.44 per MMBtu for each month of 2012.

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 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" 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 or generate income or cash flows 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 and unknown 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, 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 and advanced completion technologies;
- 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 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;
- 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 and hydraulic fracturing and laws and regulations imposing conditions and restrictions on drilling and completion operations;
- 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;
- 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 developments around the world, including in the areas in which EOG operates;
- the timing and impact of liquefied natural gas imports;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors," on pages 14 through 20 of EOG's Annual Report on Form 10-K for the year ended December 31, 2010.

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 41 through 45 of EOG's Annual Report on Form 10-K for the year ended December 31, 2010, filed on February 24, 2011 (EOG's 2010 Annual Report); and (ii) Note 11, "Risk Management Activities," to EOG's Consolidated Financial Statements on pages F-26 through F-29 of EOG's 2010 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 13 to 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 by EOG in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the 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 9 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 (1)	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 (2)
April 1, 2011 - April 30, 2011	7,602	$ 115.44	-	6,386,200
May 1, 2011 - May 31, 2011	4,856	108.91	-	6,386,200
June 1, 2011 - June 30, 2011	3,268	106.96	-	6,386,200
Total	15,726	111.66	-	

(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 2011, EOG did not repurchase any shares under the Board-authorized repurchase program.

ITEM 6. EXHIBITS

Exhibit No.		Description
* 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.
* **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 - Three Months Ended June 30, 2011 and 2010 and Six Months Ended June 30, 2011 and 2010, (ii) the Consolidated Balance Sheets - June 30, 2011 and December 31, 2010, (iii) the Consolidated Statements of Cash Flows - Six Months Ended June 30, 2011 and 2010 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 4, 2011

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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