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 September 30, 2005

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

Commission File Number: 1-9743

eog resources

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.)

333 Clay Street, Suite 4200, Houston, Texas 77002-7361
(Address of principal executive offices, including 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 is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☒ No ☐

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 issuer's classes of common stock, as of October 27, 2005.

Title of each class	Number of shares
Common Stock, par value $0.01 per share	241,580,849

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 September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Net Operating Revenues				
Wellhead Natural Gas	$ 751,239	$ 447,784	$ 1,919,909	$ 1,294,789
Wellhead Crude Oil, Condensate and Natural Gas Liquids	181,741	123,379	483,584	316,238
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	-	22,743	(940)	(36,275)
Other, Net	1,465	324	3,972	2,819
Total	934,445	594,230	2,406,525	1,577,571
Operating Expenses				
Lease and Well, including Transportation	92,010	69,027	261,736	198,976
Exploration Costs	32,023	21,874	94,833	67,466
Dry Hole Costs	19,130	21,114	56,249	50,205
Impairments	18,292	17,930	54,695	51,289
Depreciation, Depletion and Amortization	164,372	130,257	477,284	360,278
General and Administrative	30,079	29,576	88,879	80,861
Taxes Other Than Income	56,383	29,952	135,909	95,824
Total	412,289	319,730	1,169,585	904,899
Operating Income	522,156	274,500	1,236,940	672,672
Other Income, Net	10,159	3,953	22,498	2,649
Income Before Interest Expense and Income Taxes	532,315	278,453	1,259,438	675,321
Interest Expense, Net	13,877	16,110	42,521	48,209
Income Before Income Taxes	518,438	262,343	1,216,917	627,112
Income Tax Provision	174,677	90,033	420,997	209,012
Net Income	343,761	172,310	795,920	418,100
Preferred Stock Dividends	1,857	2,758	5,573	8,274
Net Income Available to Common	$ 341,904	$ 169,552	$ 790,347	$ 409,826
Net Income Per Share Available to Common				
Basic	$ 1.43	$ 0.72	$ 3.32	$ 1.76
Diluted	$ 1.40	$ 0.71	$ 3.25	$ 1.73
Average Number of Common Shares				
Basic	239,344	234,822	238,291	232,969
Diluted	244,900	239,354	243,530	237,420

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

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

	September 30, 2005	December 31, 2004
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 341,061	$ 20,980
Accounts Receivable, Net	631,320	447,742
Inventories	54,887	40,037
Assets from Price Risk Management Activities	-	10,747
Deferred Income Taxes	28,134	22,227
Other	88,610	45,070
Total	1,144,012	586,803
Oil and Gas Properties (Successful Efforts Method)	10,719,464	9,599,276
Less: Accumulated Depreciation, Depletion and Amortization	(4,939,051)	(4,497,673)
Net Oil and Gas Properties	5,780,413	5,101,603
Other Assets	102,128	110,517
Total Assets	$ 7,026,553	$ 5,798,923
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 508,815	$ 424,581
Accrued Taxes Payable	97,613	51,116
Dividends Payable	9,859	7,394
Deferred Income Taxes	105,377	103,933
Other	51,594	45,180
Total	773,258	632,204
Long-Term Debt	1,042,772	1,077,622
Other Liabilities	271,365	241,319
Deferred Income Taxes	1,087,703	902,354
Shareholders' Equity		
Preferred Stock, $0.01 Par, 10,000,000 Shares Authorized: Series B, 100,000 Shares Issued, Cumulative, $100,000,000 Liquidation Preference	99,003	98,826
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 249,460,000 Shares Issued	202,495	201,247
Additional Paid in Capital	72,773	21,047
Unearned Compensation	(39,361)	(29,861)
Accumulated Other Comprehensive Income	188,864	148,015
Retained Earnings	3,468,406	2,706,845
Common Stock Held in Treasury, 7,916,180 Shares at September 30, 2005 and 11,605,112 Shares at December 31, 2004	(140,725)	(200,695)
Total Shareholders' Equity	3,851,455	2,945,424
Total Liabilities and Shareholders' Equity	$ 7,026,553	$ 5,798,923

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

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

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Cash Flows From Operating Activities		
Reconciliation of Net Income to Net Operating Cash Provided by Operating Activities:		
Net Income	$ 795,920	$ 418,100
Items Not Requiring Cash		
Depreciation, Depletion and Amortization	477,284	360,278
Impairments	54,695	51,289
Deferred Income Taxes	172,015	158,216
Other, Net	8,722	11,571
Dry Hole Costs	56,249	50,205
Mark-to-Market Commodity Derivative Contracts		
Total Losses	940	36,275
Realized Gains (Losses)	9,807	(70,507)
Tax Benefits from Stock Options Exercised	40,347	20,730
Other, Net	(10,558)	(208)
Changes in Components of Working Capital and Other Liabilities		
Accounts Receivable	(171,428)	(54,172)
Inventories	(14,736)	(8,711)
Accounts Payable	79,239	56,557
Accrued Taxes Payable	8,018	6,428
Other Liabilities	(1,164)	4,620
Other, Net	804	(5,201)
Changes in Components of Working Capital Associated with Investing and Financing Activities	(1,942)	(17,596)
Net Cash Provided by Operating Activities	1,504,212	1,017,874
Investing Cash Flows		
Additions to Oil and Gas Properties	(1,223,715)	(941,670)
Proceeds from Sales of Assets	56,990	12,771
Changes in Components of Working Capital Associated with Investing Activities	2,572	17,022
Other, Net	(13,986)	(16,215)
Net Cash Used in Investing Activities	(1,178,139)	(928,092)
Financing Cash Flows		
Net Commercial Paper and Line of Credit Borrowings (Repayments)	40,150	(20,900)
Long-Term Debt Borrowings	-	150,000
Long-Term Debt Repayments	(75,000)	(175,000)
Dividends Paid	(31,575)	(27,841)
Proceeds from Stock Options Exercised	56,437	59,582
Other, Net	(1,462)	(958)
Net Cash Used in Financing Activities	(11,450)	(15,117)
Effect of Exchange Rate Changes on Cash	5,458	2,800
Increase in Cash and Cash Equivalents	320,081	77,465
Cash and Cash Equivalents at Beginning of Period	20,980	4,443
Cash and Cash Equivalents at End of Period	$ 341,061	$ 81,908

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. and subsidiaries (EOG) included herein have been prepared by management without audit pursuant to the rules and regulations of the 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. Certain information and notes normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations. However, management believes that the disclosures are adequate to make the 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, 2004 (EOG's 2004 Annual Report).

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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.

On February 2, 2005, EOG announced that the Board of Directors had approved a two-for-one stock split in the form of a stock dividend, payable to record holders as of February 15, 2005 and issued on March 1, 2005. All share and per share amounts in the financial statements and accompanying footnotes for all periods have been restated to reflect the two-for-one stock split paid to common shareholders.

On February 24, 2005, the Board of Directors approved an amendment to EOG's Restated Certificate of Incorporation to increase the number of EOG's authorized shares of common stock to 640 million. The shareholders approved the increase at the Annual Meeting of Shareholders on May 3, 2005, and the amendment was filed with the Delaware Secretary of State on May 9, 2005.

Certain reclassifications have been made to prior period financial statements to conform with the current presentation.

Derivative Instruments. As more fully discussed in Note 11 to the consolidated financial statements included in EOG's 2004 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 natural gas and crude oil. EOG utilizes financial commodity derivative instruments, primarily collars and price swaps, as the means to manage this price risk. During 2004 and the first three months of 2005, EOG accounted for the financial commodity derivative contracts using the mark-to-market accounting method. EOG has not been a party to any financial commodity derivative contracts since March 31, 2005. 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 these various physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

Recently Issued Accounting Standards and Developments. On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was enacted. Among other things, the Act creates a temporary incentive for United States corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. On or before December 31, 2005, EOG expects to receive a $450 million foreign dividend qualifying under this incentive. On October 28, 2005, EOG's Board of Directors approved EOG's Domestic Reinvestment Plan, under which the categories of qualified expenditures are worker compensation and infrastructure and capital investments in the United States. EOG's fourth quarter 2005 results will include a tax charge of approximately $24 million as a result of the planned repatriation.

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 153, "Exchanges of Nonmonetary Assets, an Amendment of Accounting Principles Board (APB) Opinion No. 29," which provides that all nonmonetary asset exchanges that have commercial substance must be measured based on the fair value of the assets exchanged and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion No. 29 previously exempted all exchanges of similar productive assets from fair value accounting, therefore resulting in no gain or loss recorded for such exchanges. SFAS No. 153 became effective for fiscal periods beginning on or after June 15, 2005. EOG adopted SFAS No. 153 effective July 1, 2005. The adoption of SFAS No. 153 did not have a material impact on EOG's financial statements.

In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment," which supersedes SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure an amendment of FASB Statement No. 123." SFAS No. 123(R) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This eliminates the exception to account for such awards using the intrinsic method previously allowable under APB Opinion No. 25 "Accounting for Stock Issued to Employees." In March 2005, the SEC issued Staff Accounting Bulletin (SAB) 107. Among other things, SAB 107 provides interpretive guidance related to the interaction between SFAS No. 123(R) and certain SEC rules and regulations, as well as provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. On April 14, 2005, the SEC issued press release 2005-57 which amends the compliance date of SFAS No. 123(R). As a result, SFAS No. 123(R) will be effective for annual reporting periods beginning on or after June 15, 2005. EOG currently expects to adopt SFAS No. 123(R) effective January 1, 2006 using the modified prospective method.

Until the adoption of SFAS No. 123(R), EOG continues to account for its stock option plans and employee stock purchase plans under the provisions and related interpretations of APB Opinion No. 25. No compensation expense is recognized for such options. As allowed by SFAS No. 123, "Accounting for Stock-Based Compensation," issued in 1995, EOG has continued to apply APB Opinion No. 25 for purposes of determining net income and to present the pro forma disclosures required by SFAS No. 123. See Note 2.

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, "Accounting for Conditional Asset Retirement Obligations." The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. FIN No. 47 is effective for fiscal years ending after December 15, 2005. EOG does not expect FIN No. 47 will have a material impact on its financial statements.

In April 2005, the FASB issued Staff Position No. FAS (FSP) 19-1, "Accounting for Suspended Well Costs," which amended SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." FSP No. 19-1 allows exploratory well costs to continue to be capitalized beyond one year of the drilling completion date when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. EOG adopted FSP No. 19-1 effective July 1, 2005. The adoption of FSP No. 19-1 did not have a material impact on EOG's financial statements. See Note 8.

2. Stock-based Compensation

The fair value of stock option grants made prior to August 2004 and awards under the Employee Stock Purchase Plan is estimated using the Black-Scholes Option Pricing Model. Certain of EOG's employee stock options granted in 2004 and 2005 contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price reaches 200% of the grant price for five consecutive trading days (Capped Option). EOG may or may not grant options with this capped feature in the future. The fair value of each Capped Option grant is estimated using a Monte Carlo simulation. Effective May 2005, the fair value of stock option grants not containing the Capped Option feature is estimated using the Hull-White II Model, a lattice option pricing model.

EOG's pro forma Net Income and Net Income Per Share Available to Common for the three-month and nine-month periods ended September 30, 2005 and 2004, had compensation costs been recorded in accordance with SFAS No. 123, are presented below (in millions, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
Net Income Available to Common - As Reported	$ 341.9	$ 169.6	$ 790.3	$ 409.8
Deduct: Total Stock-Based Employee Compensation Expense, Net of Income Tax	(3.5)	(3.3)	(9.7)	(8.6)
Net Income Available to Common - Pro Forma	$ 338.4	$ 166.3	$ 780.6	$ 401.2
Net Income Per Share Available to Common				
Basic - As Reported	$ 1.43	$ 0.72	$ 3.32	$ 1.76
Basic - Pro Forma	$ 1.41	$ 0.71	$ 3.28	$ 1.72
Diluted - As Reported	$ 1.40	$ 0.71	$ 3.25	$ 1.73
Diluted - Pro Forma	$ 1.38	$ 0.70	$ 3.21	$ 1.69

The effects of applying SFAS No. 123, as amended, in this pro forma disclosure should not be interpreted as being indicative of future effects, including the extent and timing of additional future awards.

Restricted Stock and Units. Under EOG's various stock plans, employees may be granted restricted stock and/or units without cost to them. Related compensation expense for the three-month periods ended September 30, 2005 and 2004 was $3.1 million and $2.5 million, respectively. Related compensation expense for the nine-month periods ended September 30, 2005 and 2004 was $8.8 million and $6.9 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

3. Earnings Per Share

The following table sets forth the computation of Net Income Per Share Available to Common for the three-month and nine-month periods ended September 30 (in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Numerator for Basic and Diluted Earnings Per Share -				
Net Income Available to Common	$ 341,904	$ 169,552	$ 790,347	$ 409,826
Denominator for Basic Earnings Per Share -				
Weighted Average Shares	239,344	234,822	238,291	232,969
Potential Dilutive Common Shares -				
Stock Options	4,251	3,489	4,034	3,467
Restricted Stock and Units	1,305	1,043	1,205	984
Denominator for Diluted Earnings Per Share -				
Adjusted Weighted Average Shares	244,900	239,354	243,530	237,420
Net Income Per Share Available to Common				
Basic	$ 1.43	$ 0.72	$ 3.32	$ 1.76
Diluted	$ 1.40	$ 0.71	$ 3.25	$ 1.73

4. Supplemental Cash Flow Information

The amounts of cash paid for interest (net of amounts capitalized) and income taxes are as follows (in thousands):

	Nine Months Ended September 30,	
	2005	2004
Interest	$ 30,892	$ 36,933
Income Taxes	$ 225,933	$ 48,659

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

5. Comprehensive Income

The following table presents the components of EOG's comprehensive income for the three-month and nine-month periods ended September 30 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Comprehensive Income				
Net Income	$ 343,761	$ 172,310	$ 795,920	$ 418,100
Other Comprehensive Income (Loss)				
Foreign Currency Translation Adjustment	65,812	56,919	45,597	26,173
Foreign Currency Swap Transaction	(2,537)	2,649	(7,267)	132
Income Tax Benefit (Provision) Related to Foreign Currency Swap Transaction	904	(847)	2,519	(45)
Total	$ 407,940	$ 231,031	$ 836,769	$ 444,360

6. Segment Information

Selected financial information by reportable segment is presented below for the three-month and nine-month periods ended September 30 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Net Operating Revenues				
United States	$ 689,521	$ 438,007	$ 1,724,342	$ 1,161,033
Canada	162,203	109,066	434,402	309,833
Trinidad	60,308	43,427	186,135 (1)	102,975
United Kingdom (2)	22,413	3,730	61,646	3,730
Total	$ 934,445	$ 594,230	$ 2,406,525	$ 1,577,571
Operating Income (Loss)				
United States	$ 386,642	$ 198,978	$ 851,792	$ 452,096
Canada	89,586	48,121	233,244	157,139
Trinidad	38,406	26,011	131,818 (1)	67,289
United Kingdom (2)	7,522	1,390	20,086	(3,852)
Total	522,156	274,500	1,236,940	672,672
Reconciling Items				
Other Income, Net	10,159	3,953	22,498	2,649
Interest Expense, Net	13,877	16,110	42,521	48,209
Income Before Income Taxes	$ 518,438	$ 262,343	$ 1,216,917	$ 627,112

(1) Includes $19.3 million recorded in the second quarter of 2005 related to an amended Trinidad take-or-pay contract.
(2) Production in the United Kingdom commenced in August 2004.

7. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of short-term and long-term legal obligations associated with the retirement of oil and gas properties pursuant to SFAS No. 143, "Accounting for Asset Retirement Obligations," for the nine months ended September 30, 2005 (in thousands):

	Asset Retirement Obligations		
	Short-Term	Long-Term	Total
Balance at December 31, 2004	$ 6,970	$ 131,789	$ 138,759
Liabilities Incurred	1,288	4,870	6,158
Liabilities Settled	(2,011)	(1,468)	(3,479)
Accretion	100	5,235	5,335
Revisions	(1,438)	1,553	115
Reclassification	785	(785)	-
Foreign Currency Translations	164	1,603	1,767
Balance at September 30, 2005	$ 5,858	$ 142,797	$ 148,655

8. Suspended Well Costs

EOG's net changes in suspended well costs for the nine months ended September 30, 2005, as well as for the years ended December 31, 2004 and 2003, in accordance with FSP No. 19-1 "Accounting for Suspended Well Costs," are presented below (in thousands):

	Nine Months Ended September 30,	Year Ended December 31,	
	2005	2004	2003
Balance at January 1	$ 23,847	$ 29,480	$ 11,757
Additions Pending the Determination of Proved Reserves	37,371	21,223	24,640
Reclassifications to Proved Properties	(9,235)	(22,984)	(7,184)
Charged to Dry Hole Costs	(16,355)	(4,295)	-
Foreign Currency Translation	554	423	267
Ending Balance	$ 36,182	$ 23,847	$ 29,480

The following table provides an aging of suspended well costs as of September 30, 2005, and December 31, 2004 and 2003 (in thousands, except well count):

	As of September 30, 2005	As of December 31, 2004	As of December 31, 2003
Capitalized exploratory well costs that have been capitalized for a period less than one year	$ 27,006	$ 19,597	$ 25,035
Capitalized exploratory well costs that have been capitalized for a period greater than one year	9,176 (1)	4,250 (2)	4,445 (2)
Total	$ 36,182	$ 23,847	$ 29,480
Number of exploratory wells that have been capitalized for a period greater than one year	2	1	1

(1) Costs as of September 30, 2005 related to an outside operated, deepwater offshore Gulf of Mexico discovery ($4.3 million) and an outside operated, winter access only, Northwest Territories discovery in Northern Canada ($4.9 million). EOG is continuing to evaluate these discoveries and plans to drill an additional exploratory well in each discovery.

(2) Costs related to the deepwater offshore Gulf of Mexico discovery.

9. Commitments and Contingencies

There are various suits and claims against EOG that have arisen in the ordinary course of business. Management believes that the chance that these suits and claims will individually, or in the aggregate, have a material adverse effect on the financial condition or results of operations of EOG is remote. When necessary, EOG has made accruals in accordance with SFAS No. 5, "Accounting for Contingencies," in order to provide for these matters.

10. Pension and Postretirement Benefits

Pension Plans. EOG has non-contributory defined contribution pension plans and matched defined contribution savings plans in place for most of its employees. For the three-month periods ended September 30, 2005 and 2004, EOG's total contributions to these pension plans were $3.2 million and $2.1 million, respectively. For the nine-month periods ended September 30, 2005 and 2004, EOG's total contributions to these pension plans were $9.4 million and $8.2 million, respectively.

Postretirement Medical Plan. The following table summarizes the benefit expense for EOG's contributory defined dollar benefit postretirement medical plan for the three-month and nine-month periods ended September 30 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Service Cost	$ 41	$ 33	$ 123	$ 139
Interest Cost	31	28	93	107
Expected Return on Plan Assets	-	-	-	-
Amortization of Prior Service Cost	32	32	97	97
Amortization of Net Actuarial (Gain) Loss	(18)	(18)	(53)	(36)
Net Periodic Benefit Cost	$ 86	$ 75	$ 260	$ 307

EOG previously disclosed in its financial statements for the year ended December 31, 2004, that it expected to contribute $84,000 to its postretirement plan in 2005. As of September 30, 2005, $49,000 of contributions have been made. EOG presently anticipates contributing an additional $19,000 to fund its postretirement plan in 2005 for a total of $68,000, a downward revision from EOG's original estimate due to an actuarial revaluation to incorporate the impact of the Medicare Prescription Improvement and Modernization Act of 2003.

11. Long-Term Debt

On August 26, 2005, EOG repaid the remaining $75 million of its $150 million floating rate Senior Unsecured Term Loan Facility with a maturity date of October 30, 2005.

On June 28, 2005, EOG entered into a new 5-year $600 million unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders and JPMorgan Chase Bank, N.A., as Administrative Agent, and concurrently terminated the existing $600 million 3-year unsecured credit facility scheduled to expire in July 2006. Under the Agreement, EOG has the option to extend the term for successive one-year periods with the consent of the majority banks and to request increases in the aggregate commitments to an amount not to exceed $1 billion. The Agreement also provides for the allocation, at the option of EOG, of up to $75 million of the $600 million each to EOG's current United Kingdom subsidiary and one of its Canadian subsidiaries. Interest accrues on advances at LIBOR plus an applicable margin (Eurodollar rate) or at the Administrative Agent's base rate, as selected by EOG. Advances to the Canadian or the United Kingdom subsidiaries, should they occur, would be guaranteed by EOG and would bear interest at a rate calculated in accordance with the Agreement. In addition, the Agreement provides EOG the option to request letters of credit to be issued in an aggregate amount of up to $200 million. There are no borrowings or letters of credit currently outstanding under the Agreement. The applicable base rate and Eurodollar rate, had there been an amount borrowed under the Agreement, would have been 6.75% and 4.08% at September 30, 2005, respectively.

On September 15, 2004, EOG repaid in full upon maturity its $100 million, 6.50% Notes due 2004.

On March 31, 2004, EOG repaid $75 million of its $150 million floating rate Senior Unsecured Term Loan Facility with a maturity date of October 30, 2005.

On March 9, 2004, under Rule 144A of the Securities Act of 1933, as amended, EOG Resources Canada Inc., a wholly owned subsidiary of EOG, issued notes with a total principal amount of US$150 million, an annual interest rate of 4.75% and a maturity date of March 15, 2014. The notes are guaranteed by EOG. In conjunction with the offering, EOG entered into a cross currency swap transaction with multiple banks for the equivalent amount of the notes, which has in effect converted this indebtedness into CAD$201.3 million with a 5.275% interest rate.

12. Subsequent Events

In October 2005, a wholly-owned foreign subsidiary of EOG entered into a $600 million, 3-year unsecured Senior Term Loan Agreement (Term Loan Agreement) with The Bank of Nova Scotia, as Administrative Agent, and certain banks, as lenders. All borrowings under this agreement will be made as term loans and will be guaranteed by EOG. Proceeds from the Term Loan Agreement will be used for general corporate purposes, including funding distributions ultimately to EOG from its foreign subsidiaries to realize the benefit of the recent favorable United States tax legislation regarding repatriation of foreign earnings under the American Jobs Creation Act of 2004. Borrowings up to $600 million under the Term Loan Agreement will be available in multiple drawings through December 31, 2005. Subsequent to December 31, 2005, borrowing capacity under the Term Loan Agreement will be reduced to $100 million (or the remaining undrawn amount, if less), and such amount will be available for an additional one-year period. Borrowings under the Term Loan Agreement accrue interest at a LIBOR rate plus an applicable margin or at the Administrative Agent's base rate, as selected by the borrower. As of the date hereof, the borrower has not borrowed under the Term Loan Agreement.

On October 28, 2005, the Board of Directors approved management's plan to redeem the remaining $174 million outstanding principal amount of the 6.00% Notes due 2008 (2008 Notes) in accordance with the terms of the indenture and the officer's certificate establishing the 2008 Notes. On November 1, 2005, notice was delivered to the holders of the 2008 Notes that EOG will redeem all 2008 Notes on December 5, 2005 (Redemption Date). The redemption price will be determined three business days prior to the Redemption Date and will be equal to the *greater* of (i) 100% of the principal amount or (ii) the sum of the present values of the remaining scheduled payments of principal and interest discounted to the Redemption Date at the applicable treasury rate plus 20 basis points, plus any accrued and unpaid interest through the Redemption Date.

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. (EOG) is one of the largest independent (non-integrated) oil and natural gas companies in the United States with proved reserves in the United States, Canada, offshore Trinidad and the United Kingdom North Sea. EOG operates under a consistent business and operational strategy which focuses predominantly on achieving a strong reinvestment rate of return, drilling internally generated prospects, delivering long-term production growth and maintaining a strong balance sheet.

Operations. EOG's effort to identify plays with larger reserve potential has proven a successful supplement to its base development and exploitation program in the United States and Canada. EOG plans to continue 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 several larger potential plays under way in Wyoming, Utah, Texas, Oklahoma and western Canada.

Although EOG continues to focus on United States and Canada natural gas, EOG sees an increasing linkage between United States and Canada natural gas demand and Trinidad natural gas supply. For example, liquefied natural gas (LNG) imports from existing and planned facilities in Trinidad are serious contenders to meet increasing United States natural gas demand. In addition, petro-chemical production has been relocating from the United States and Canada to Trinidad, driven by attractive natural gas feedstock prices in the island nation. EOG anticipates that its existing position with the supply contracts to two ammonia plants, a new methanol plant and an LNG plant that is presently under construction and is expected to start up in early 2006, will continue to give its portfolio an even broader exposure to United States and Canada natural gas fundamentals. In mid-September 2005, the methanol plant commenced operations. EOG utilizes production from the U(a) and SECC blocks to supply the estimated net 60 MMcf per day of natural gas under the supply contract.

In July 2005, EOG, through its subsidiary, EOG Resources Trinidad Block 4(a) Unlimited, signed a production sharing contract with the Government of Trinidad and Tobago for Block 4(a) which is located off Trinidad's east coast. EOG holds a 90% working interest in Block 4(a).

EOG continues its progress in the Southern Gas Basin of the United Kingdom North Sea. In addition to EOG's production from the Valkyrie and Arthur fields, production from the Arthur 2 well, in which EOG has a 30% working interest, commenced in July 2005. The Arthur 2 well was drilled during the first quarter of 2005 as an extension to the Arthur 1 discovery. EOG continues to review additional opportunities in the United Kingdom North Sea.

Capital Structure. One of management's key strategies is to keep a strong balance sheet with a consistently below average year-end debt-to-total capitalization ratio as compared to those in EOG's peer group. At September 30, 2005, EOG's debt-to-total capitalization ratio was 21%, down from 27% at December 31, 2004. In addition, EOG's cash balance increased to $341 million. During the first nine months of 2005, EOG funded its capital programs by utilizing cash provided from its operating activities. As management continues to assess price forecast and demand trends for 2005, EOG believes that operations and capital expenditure activity can be funded by cash from operations.

For 2005, EOG's estimated exploration and development expenditure budget is approximately $1.8 billion, excluding acquisitions. United States and Canada natural gas drilling activity continues to be a key component of this effort. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was enacted. Among other things, the Act creates a temporary incentive for United States corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. On or before December 31, 2005, EOG expects to receive a $450 million foreign dividend qualifying under this incentive. On October 28, 2005, EOG's Board of Directors approved EOG's Domestic Reinvestment Plan, under which the categories of qualified expenditures are worker compensation and infrastructure and capital investments in the United States. EOG's fourth quarter 2005 results will include a tax charge of approximately $24 million as a result of the planned repatriation.

Results of Operations

The following review of operations for the three-month and nine-month periods ended September 30, 2005 and 2004 should be read in conjunction with the consolidated financial statements of EOG and notes thereto included with this quarterly report on Form 10-Q.

Three Months Ended September 30, 2005 vs. Three Months Ended September 30, 2004

Net Operating Revenues. During the third quarter of 2005, net operating revenues increased $340 million to $934 million from $594 million for the same period in 2004. Total wellhead revenues, which are revenues generated from sales of natural gas, crude oil, condensate and natural gas liquids from producing wells, increased $362 million, or 63%, to $933 million, as compared to $571 million for the third quarter of 2004.

Wellhead volume and price statistics for the three-month periods ended September 30 were as follows:

		Three Months Ended September 30,	
		2005	2004
Natural Gas Volumes (MMcf per day)(1)			
United States		724	623
Canada		226	211
United States and Canada		950	834
Trinidad		213	203
United Kingdom		44	8
Total		1,207	1,045
Average Natural Gas Prices ($/Mcf)(2)			
United States	$	8.19	$ 5.57
Canada		7.12	4.99
United States and Canada		7.94	5.42
Trinidad		1.86	1.50
United Kingdom		5.14	5.30
Composite		6.77	4.66
Crude Oil and Condensate Volumes (MBbl per day)(1)			
United States		21.2	21.0
Canada		2.3	2.7
United States and Canada		23.5	23.7
Trinidad		4.2	4.0
United Kingdom		0.3	-
Total		28.0	27.7
Average Crude Oil and Condensate Prices ($/Bbl)(2)			
United States	$	61.63	$ 43.30
Canada		57.08	40.17
United States and Canada		61.19	42.94
Trinidad		61.93	42.06
United Kingdom		53.80	-
Composite		61.22	42.81
Natural Gas Liquids Volumes (MBbl per day)(1)			
United States		6.0	4.4
Canada		0.3 (4)	0.9
Total		6.3	5.3
Average Natural Gas Liquids Prices ($/Bbl)(2)			
United States	$	39.80	$ 30.07
Canada		69.43 (4)	23.58
Composite		41.25	29.02
Natural Gas Equivalent Volumes (MMcfe per day)(3)			
United States		887	775
Canada		242	233
United States and Canada		1,129	1,008
Trinidad		238	227
United Kingdom		46	8
Total		1,413	1,243
Total Bcfe(3) Deliveries		130.0	114.4

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Dollars per thousand cubic feet or per barrel, as applicable.
(3) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil, condensate and natural gas liquids.
(4) Includes 0.08 MBbl per day adjustment in the third quarter of 2005. Excluding the adjustment, the average natural gas liquid price was $44.50.

Wellhead natural gas revenues for the third quarter of 2005 increased $303 million, or 68%, to $751 million from $448 million for the same period of 2004. The increase was due to a higher composite average wellhead natural gas price ($234 million) and increased natural gas deliveries ($69 million). The composite average wellhead price for natural gas increased 45% to $6.77 per Mcf for the third quarter of 2005 from $4.66 per Mcf for the same period in 2004.

Natural gas deliveries increased 162 MMcf per day, or 16%, to 1,207 MMcf per day for the third quarter of 2005 from 1,045 MMcf per day for the same prior year period. The increase was due to higher production of 101 MMcf per day in the United States, 36 MMcf per day in the United Kingdom, 15 MMcf per day in Canada and 10 MMcf per day in Trinidad. The increase in the United States was primarily attributable to increased production from Texas (79 MMcf per day) and Louisiana (22 MMcf per day). The increase in the United Kingdom was due to the commencement of production from the Arthur field in January 2005 (31 MMcf per day) and increased production from the Valkyrie field, which commenced production in August 2004 (5 MMcf per day). The increase in Canada was a result of the drilling program, primarily in the Wapiti and Drumheller areas. The higher Trinidadian production was primarily attributable to increased demand from the purchaser under the Nitrogen (2000) Unlimited (N2000) ammonia plant contract (12 MMcf per day) and the contract to supply natural gas to a new methanol plant, which commenced operations in mid-September (8 MMcf per day). Partially offsetting these increases was decreased production from the SECC block due primarily to temporary operational issues encountered by the purchaser (11 MMcf per day).

Wellhead crude oil and condensate revenues increased $49 million, or 45%, in the third quarter of 2005 to $158 million from $109 million as compared to the same period in 2004, primarily due to an increase in the composite average wellhead crude oil and condensate price. The composite average wellhead crude oil and condensate price for the third quarter of 2005 was $61.22 per barrel compared to $42.81 per barrel for the same period in 2004.

Natural gas liquids revenues for the third quarter of 2005 were $10 million higher than a year ago due to the increase in the composite average price ($7 million) and increases in deliveries ($3 million).

EOG has not been a party to any financial commodity derivative contracts since March 31, 2005. During the third quarter of 2004, EOG recognized a gain on mark-to-market financial commodity derivative contracts of $23 million and the net cash outflow related to settled natural gas financial collar contracts and settled natural gas and crude oil financial price swap contracts was $32 million.

Operating and Other Expenses. For the third quarter of 2005, operating expenses of $412 million were $92 million higher than the $320 million incurred in the third quarter of 2004. The following table presents the costs per Mcfe for the three-month periods ended September 30:

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004
Lease and Well, including Transportation	$ 0.71	$ 0.60
Depreciation, Depletion and Amortization (DD&A)	1.26	1.14
General and Administrative (G&A)	0.23	0.26
Taxes Other Than Income	0.43	0.26
Interest Expense, Net	0.11	0.14
Total Per-Unit Costs*	$ 2.74	$ 2.40

* Total per-unit costs do not include exploration costs, dry hole costs and impairments.

The higher per-unit rates of lease and well, including transportation, DD&A and taxes other than income for the three-month period ended September 30, 2005 compared to the same period in 2004 were due primarily to the reasons set forth below.

Lease and well expense includes 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 expense can be divided into the following categories: costs to operate and maintain EOG's oil and natural gas wells, the cost of workovers, transportation costs associated with selling hydrocarbon products and lease and well administrative expenses. Operating and maintenance expenses include, among other service costs, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep, fuel and power. Workovers are costs of 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 costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time.

Lease and well expenses of $92 million for the third quarter of 2005 were $23 million higher than the same prior year period primarily due to higher operating and maintenance expenses in the United States ($9 million), increased transportation related costs in the United States ($7 million) and the United Kingdom ($2 million), higher workover expenditures in the United States ($3 million) and higher lease and well administrative expenses in the United States ($3 million).

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual field calculations. The individual field expense is calculated by dividing sales volume by reserves and multiplying the result by the depreciable net book value. There are several factors that can impact an individual field, such as the field production profile; drilling or acquisition of new wells; disposition of existing wells; reserve revisions (upward or downward), primarily related to well performance; and impairments. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are also taken into account. Changes to the individual fields, due to any of these factors, may cause EOG's composite DD&A rate and expense to fluctuate from quarter to quarter.

DD&A expenses of $164 million for the third quarter of 2005 increased $34 million from the same prior year period primarily due to increased DD&A rates in the United States ($12 million); increased production in the United States ($14 million) and the United Kingdom ($5 million), as discussed previously in the Net Operating Revenues section; and changes in the Canadian exchange rate ($2 million).

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Taxes other than income of $56 million for the third quarter of 2005 were $26 million higher than the same prior year period primarily due to increased wellhead revenues in the United States ($14 million), additional Supplemental Petroleum Tax expense recorded in Trinidad as a result of 2005 tax legislation which increased the tax expense retroactively to January 2004 ($7 million) and production tax relief in the third quarter of 2004 in Trinidad ($2 million).

Exploration costs of $32 million for the third quarter of 2005 were $10 million higher than the same prior year period primarily due to increased geological and geophysical expenditures in the United States.

Impairments include amortization of unproved leases, as well as impairments under the Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which requires an entity to compute impairments to the carrying value of long-lived assets based on future cash flow analysis. Impairments of $18 million in the third quarter of 2005 were comparable to the third quarter of 2004. EOG recorded impairments of $6 million and $4 million for the third quarters of 2005 and 2004, respectively, under SFAS No. 144 for certain properties in the United States.

Other income, net was $10 million for the third quarter of 2005 compared to $4 million for the same prior year period. The increase was primarily due to gains on sales of properties.

Income tax provision of $175 million for the third quarter of 2005 increased $85 million compared to the same prior year period due primarily to higher pre-tax income. The net effective tax rate of 34% for the third quarter of 2005 was comparable to the same prior year period.

Nine Months Ended September 30, 2005 vs. Nine Months Ended September 30, 2004

Net Operating Revenues. During the nine months ended September 30, 2005, net operating revenues increased $829 million to $2,407 million from $1,578 million for the same prior year period. Total wellhead revenues increased $792 million, or 49% to $2,403 million as compared to $1,611 million for the same period in 2004.

Wellhead volume and price statistics for the nine-month periods ended September 30 were as follows:

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Natural Gas Volumes (MMcf per day)		
United States	707	620
Canada	229	204
United States and Canada	936	824
Trinidad	210	173
United Kingdom	38	3
Total	1,184	1,000
Average Natural Gas Prices ($/Mcf)		
United States	$ 6.96	$ 5.55
Canada	6.28	5.00
United States and Canada	6.79	5.41
Trinidad	2.18 [(1)]	1.46
United Kingdom	5.72	5.30
Composite	5.94	4.73
Crude Oil and Condensate Volumes (MBbl per day)		
United States	21.8	20.7
Canada	2.4	2.6
United States and Canada	24.2	23.3
Trinidad	4.2	3.2
United Kingdom	0.2	-
Total	28.6	26.5
Average Crude Oil and Condensate Prices ($/Bbl)		
United States	$ 53.75	$ 38.57
Canada	49.26	35.89
United States and Canada	53.30	38.26
Trinidad	53.56	38.19
United Kingdom	48.75	-
Composite	53.30	38.26
Natural Gas Liquids Volumes (MBbl per day)		
United States	6.5	4.7
Canada	1.0	0.7
Total	7.5	5.4
Average Natural Gas Liquids Prices ($/Bbl)		
United States	$ 33.07	$ 26.09
Canada	33.10	21.65
Composite	33.08	25.52
Natural Gas Equivalent Volumes (MMcfe per day)		
United States	876	772
Canada	250	224
United States and Canada	1,126	996
Trinidad	236	192
United Kingdom	39	3
Total	1,401	1,191
Total Bcfe Deliveries	382.3	326.5

(1) Includes $0.34 per Mcf as a result of a revenue adjustment related to an amended Trinidad take-or-pay contract.

Wellhead natural gas revenues for the first nine months of 2005 increased $625 million, or 48%, to $1,920 million from $1,295 million for the same period of 2004 due to a higher composite average wellhead natural gas price ($372 million), increased natural gas deliveries ($234 million) and a revenue adjustment related to an amended Trinidad take-or-pay contract ($19 million) in the second quarter of 2005. The composite average wellhead price for natural gas increased 26% to $5.94 per Mcf from $4.73 per Mcf for the same period of 2004. Excluding the aforementioned adjustment, the composite average wellhead price for natural gas increased 24% to $5.88 per Mcf from $4.73 per Mcf for the same period in 2004. This adjustment increased the average Trinidad wellhead natural gas price by $0.34 per Mcf for the first nine months of 2005.

Natural gas deliveries increased 184 MMcf per day, or 18%, to 1,184 MMcf per day for the first nine months of 2005 from 1,000 MMcf per day for the same prior year period. The increase was due to higher production of 87 MMcf per day in the United States, 37 MMcf per day in Trinidad, 35 MMcf per day in the United Kingdom and 25 MMcf per day in Canada. The increase in the United States was primarily attributable to increased production from Texas (59 MMcf per day), Louisiana (19 MMcf per day), and the Rocky Mountain area (12 MMcf per day). The higher Trinidadian production was primarily attributable to increased demand from the purchaser under the N2000 ammonia plant contract (37 MMcf per day) and the contract to supply natural gas to a new methanol plant (3 MMcf per day). The N2000 ammonia plant commenced operations late in the second quarter of 2004. Partially offsetting these increases was decreased production from the SECC block due primarily to temporary operational issues encountered by the purchaser (3 MMcf per day). The increase in the United Kingdom was due to the commencement of production from the Arthur field in January 2005 (23 MMcf per day) and increased production from the Valkyrie field, which commenced production in August 2004 (12 MMcf per day). The increase in Canada was attributable to the drilling program, primarily in the Wapiti and Drumheller areas.

Wellhead crude oil and condensate revenues increased $138 million, or 50%, to $416 million from $278 million as compared to the same period in 2004, due to increases in both the composite average wellhead crude oil and condensate price ($117 million) and the wellhead crude oil and condensate deliveries ($21 million). The composite average wellhead crude oil and condensate price for the first nine months of 2005 was $53.30 per barrel compared to $38.26 per barrel for the same period in 2004.

Wellhead crude oil and condensate deliveries increased 2.1 MBbl per day, or 8%, in the first nine months of 2005 to 28.6 MBbl per day from 26.5 MBbl per day for the same prior year period. The increase was mainly due to increased production from both the United States (1.1 MBbl per day) and Trinidad (1.0 MBbl per day).

Natural gas liquids revenues for the first nine months of 2005 were $29 million higher than a year ago due to increases in both the composite average price ($15 million) and deliveries ($14 million).

EOG has not been a party to any financial commodity derivative contracts since March 31, 2005. During the first quarter of 2005, EOG recognized a loss on mark-to-market financial commodity derivative contracts of $1 million and a net cash inflow related to settled natural gas financial collar contracts of $10 million. During the first nine months of 2004, EOG recognized a loss from mark-to-market financial commodity derivative contracts and price swap contracts of $36 million and a net cash outflow related to settled natural gas financial collar contracts and settled natural gas and crude oil financial price swap contracts of $71 million.

Operating and Other Expenses. For the first nine months of 2005, operating expenses of $1,170 million were $265 million higher than the $905 million incurred in the same period of 2004. The following table presents the costs per Mcfe for the nine-month periods ended September 30:

	Nine Months Ended September 30,	
	2005	**2004**
Lease and Well, including Transportation	$ 0.68	$ 0.61
DD&A	1.25	1.10
G&A	0.23	0.25
Taxes Other Than Income	0.36	0.29
Interest Expense, Net	0.11	0.15
Total Per-Unit Costs*	$ 2.63	$ 2.40

* Total per-unit costs do not include exploration costs, dry hole costs and impairments.

The higher per-unit rates of lease and well, including transportation, DD&A, G&A and taxes other than income for the nine months ended September 30, 2005 compared to the same period in 2004 were due primarily to the reasons set forth below.

Lease and well expenses of $262 million for the first nine months of 2005 were $63 million higher than the same prior year period primarily due to higher operating and maintenance expenses in the United States ($22 million) and increased transportation related costs in the United States ($16 million) and the United Kingdom ($6 million). In addition, higher lease and well administrative expenses in the United States ($7 million) and changes in the Canadian exchange rate ($5 million) contributed to the increase.

DD&A expenses of $477 million for the first nine months of 2005 increased $117 million from the same prior year period primarily due to increased DD&A rates in the United States ($45 million) and Canada ($8 million); increased production in the United States ($36 million), the United Kingdom ($10 million), Canada ($8 million) and Trinidad ($3 million), as discussed previously in the Net Operating Revenues section; and changes in the Canadian exchange rate ($7 million).

G&A expenses of $89 million for the first nine months of 2005 were $8 million higher than the same prior year period. The increase was primarily due to higher employee-related costs ($8 million) resulting from expanded operations. Partially offsetting such costs were lower insurance premiums incurred during the first nine months of 2005 due primarily to the timing of the policy renewal date ($2 million).

Taxes other than income of $136 million for the first nine months of 2005 were $40 million higher than the same prior year period primarily due to increased wellhead revenues in the United States ($24 million), Trinidad ($4 million) and Canada ($2 million); additional Supplemental Petroleum Tax expense recorded in Trinidad as a result of 2005 tax legislation which increased the tax expense retroactively to January 2004 ($7 million); and 2004 production tax relief in Trinidad ($5 million); which were partially offset by a production tax audit lawsuit in the first quarter of 2004 which increased the amount for the period ($5 million).

Net interest expense of $43 million for the first nine months of 2005 decreased $5 million from the same prior year period primarily due to higher capitalized interest.

Exploration costs of $95 million for the first nine months of 2005 were $27 million higher than the same prior year period primarily due to increased geological and geophysical expenditures ($21 million) and exploration administrative expenses ($4 million) in the United States.

Impairments of $55 million for the first nine months of 2005 increased by $4 million compared to $51 million in the same prior year period primarily due to increased SFAS No. 144 related impairments in the United States ($12 million), partially offset by lower amortization of unproved leases in the United States ($9 million). EOG recorded impairments of $20 million and $8 million for the first nine months of 2005 and 2004, respectively, under SFAS No. 144 for certain properties in the United States.

Other income, net was $22 million for the first nine months of 2005 as compared to $3 million for the same period in 2004. The increase of $19 million was primarily due to foreign currency transaction losses which occurred in 2004 ($5 million), gains on sales of properties ($5 million), higher equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and N2000 ammonia plants in 2005 ($4 million), increased interest income ($3 million) and a gain on the sale of part of EOG's interest in the N2000 ammonia plant in 2005 ($2 million).

Income tax provision of $421 million for the first nine months of 2005 increased $212 million compared to the same period in 2004, due primarily to higher pre-tax income ($207 million) and a one-time Alberta (Canada) corporate tax rate reduction which occurred in the second quarter of 2004 ($5 million). The net effective tax rate for the first nine months ended 2005 increased to 35% from 33% for the same period of 2004.

Capital Resources and Liquidity

Cash Flow. The primary sources of cash for EOG during the nine months ended September 30, 2005 included funds generated from operations, proceeds from sales of partial interests in certain equity investments in Trinidad, proceeds from the sale of oil and gas properties, proceeds from sales of treasury stock attributable to employee stock option exercises and proceeds from new borrowings. Primary cash outflows included funds used in operations, exploration and development expenditures, oil and gas property acquisitions, repayment of debt and dividend payments to shareholders. During the first nine months of 2005, EOG's cash balance increased $320 million to $341 million from $21 million at December 31, 2004. The cash balance as of September 30, 2005 was primarily maintained in bank accounts associated with EOG's international operations.

Net cash provided by operating activities of $1,504 million for the first nine months of 2005 increased $486 million compared to the same period in 2004 primarily reflecting an increase in wellhead revenues ($792 million), a change in the net cash flows from settlement of financial commodity derivative contracts ($80 million) and an increase in tax benefits from stock options exercised ($20 million), partially offset by an increase in cash paid for income taxes ($177 million), an increase in cash operating expenses ($138 million) and unfavorable changes in working capital and other liabilities ($83 million).

Net cash used in investing activities of $1,178 million for the first nine months of 2005 increased by $250 million compared to the same period in 2004 due primarily to increased additions to oil and gas properties ($282 million) and changes in working capital associated with investing activities ($14 million), partially offset by proceeds from sales of oil and gas properties ($26 million) and the sale of part of EOG's interest in the N2000 ammonia plant ($18 million).

Net cash used in financing activities was $11 million for the first nine months of 2005 compared to cash used of $15 million for the same period in 2004. Financing activities included proceeds from sales of treasury stock attributable to employee stock option exercises ($56 million), net commercial paper borrowings ($40 million), repayment of long-term debt ($75 million) and cash dividend payments ($32 million).

On October 28, 2005, the Board of Directors approved management's plan to redeem the remaining $174 million outstanding principal amount of the 6.00% Notes due 2008 (2008 Notes) in accordance with the terms of the indenture and the officer’s certificate establishing the 2008 Notes. On November 1, 2005, notice was delivered to the holders of the 2008 Notes that EOG will redeem all 2008 Notes on December 5, 2005 (Redemption Date). The redemption price will be determined three business days prior to the Redemption Date and will be equal to the *greater* of (i) 100% of the principal amount or (ii) the sum of the present values of the remaining scheduled payments of principal and interest discounted to the Redemption Date at the applicable treasury rate plus 20 basis points, plus any accrued and unpaid interest through the Redemption Date.

Total Exploration and Development Expenditures. The table below presents total exploration and development expenditures for the nine-month periods ended September 30 (in millions):

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
United States	$ 1,028	$ 726
Canada	221	195
United States and Canada	1,249	921
Trinidad	36	55
United Kingdom	32	29
Other	2	4
Exploration and Development Expenditures	1,319	1,009
Asset Retirement Costs	6	7
Deferred Income Tax Benefits on Acquired Properties	-	(17)
Total Exploration and Development Expenditures	$ 1,325	$ 999

Exploration and development expenditures of $1.3 billion for the first nine months of 2005 were $310 million higher than the same period in 2004. The 2005 exploration and development expenditures included $911 million in development, $367 million in exploration, $30 million in property acquisitions, and $11 million in capitalized interest. The 2004 exploration and development expenditures of $1.0 billion included $702 million in development, $293 million in exploration, $7 million in capitalized interest and $7 million in property acquisitions.

Higher development expenditures for the first nine months of 2005 of $209 million were due primarily to increased development drilling expenditures in the United States ($223 million), partially offset by decreased drilling activities in Trinidad ($41 million).

Higher exploration expenditures for the first nine months of 2005 of $74 million were due primarily to increased exploration expenses in the United States ($25 million) and increased exploratory drilling expenditures in the United States ($28 million), Canada ($9 million) and the United Kingdom ($10 million).

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. There are no material continuing commitments associated with expenditure plans.

Commodity Derivative Transactions. As more fully discussed in Note 11 to the consolidated financial statements included in EOG's 2004 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 natural gas and crude oil. EOG utilizes financial commodity derivative instruments, primarily collars and price swaps, as the means to manage this price risk. During 2004 and the first three months of 2005, EOG accounted for the financial commodity derivative contracts using the mark-to-market accounting method. EOG has not been a party to any financial commodity derivative contracts since March 31, 2005. 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 these various physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

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 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical facts, including, among others, statements regarding EOG's future financial position, business strategy, budgets, reserve information, projected levels of production, projected costs and plans and objectives of management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "strategy," "intend," "plan," "target" and "believe" or the negative of those terms or other variations of them or by comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning future operating results, the ability to replace or increase reserves or to increase production, or the ability to generate income or cash flows are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes its expectations reflected in forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will be achieved. Important factors that could cause actual results to differ materially from the expectations reflected in the forward-looking statements include, among others: the timing and extent of changes in commodity prices for crude oil, natural gas and related products, foreign currency exchange rates and interest rates; the timing and impact of liquefied natural gas imports and changes in demand or prices for ammonia or methanol; the extent and effect of any hedging activities engaged in by EOG; the extent of EOG's success in discovering, developing, marketing and producing reserves and in acquiring oil and gas properties; the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise; the availability and cost of drilling rigs, experienced drilling crews, materials and equipment used in well completions, and tubular steel; the availability, terms and timing of governmental and other permits and rights of way; the availability of pipeline transportation capacity; the extent to which EOG can economically develop its Barnett Shale acreage outside of Johnson County, Texas; whether EOG is successful in its efforts to more densely develop its acreage in the Barnett Shale and other production areas; political developments around the world; acts of war and terrorism and responses to these acts; weather; and financial market conditions. In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements might not occur. Forward-looking statements speak only as of the date made and EOG undertakes no obligation to update or revise its forward-looking statements, whether as a result of new information, future events 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 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 26 through 29 of the Annual Report on Form 10-K for the year ended December 31, 2004, filed on February 25, 2005.

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, the principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of the Evaluation Date to ensure 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 SEC'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 that occurred during the 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

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares Purchased[1]		(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs[2]
July 1, 2005 - July 31, 2005	-	$	-	-	6,386,200
August 1, 2005 - August 31, 2005	59,368		62.10	-	6,386,200
September 1, 2005 - September 30, 2005	1,030		70.55	-	6,386,200
Total	60,398	$	62.24	-	

(1) Comprises 33,079 shares that were returned to EOG in payment of the exercise price of employee stock options and 27,319 shares that were withheld by or returned to EOG to satisfy tax withholding obligations that arose upon the exercise of employee stock options or the vesting of restricted stock or units.

(2) In September 2001, EOG announced that its Board of Directors authorized the repurchase of up to 10,000,000 shares of EOG's common stock.

ITEM 6. Exhibits

*10.1 - Senior Term Loan Agreement, dated October 28, 2005, among EOG Resources, Inc., as Parent Guarantor, EOGI International Company, as Borrower, The Bank of Nova Scotia, as Administrative Agent, and the financial institutions party thereto.

*10.2 - Amended and Restated EOG Resources, Inc. Savings Plan.

*31.1 - Section 302 Certification of Periodic Report of Chief Executive Officer.

*31.2 - Section 302 Certification of Periodic Report of Principal Financial Officer.

*32.1 - Section 906 Certification of Periodic Report of Chief Executive Officer.

*32.2 - Section 906 Certification of Periodic Report of Principal Financial Officer.

*Exhibits filed herewith

SIGNATURES

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

EOG RESOURCES, INC.
(Registrant)

Date: November 1, 2005

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

EXHIBIT INDEX

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*Exhibits filed herewith