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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): February 13, 2013

EOG RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Delaware	**1-9743**	**47-0684736**
(State or other jurisdiction of incorporation)	(Commission File Number)	(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)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

EOG RESOURCES, INC.

Item 2.02 Results of Operations and Financial Condition.

On February 13, 2013, EOG Resources, Inc. issued a press release announcing fourth quarter 2012 financial and operational results and first quarter and full year 2013 forecast and benchmark commodity pricing information (see Item 7.01 below). A copy of this release is attached as Exhibit 99.1 to this filing and is incorporated herein by reference. This information shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended.

Item 7.01 Regulation FD Disclosure.

Accompanying the press release announcing fourth quarter 2012 financial and operational results attached hereto as Exhibit 99.1 is first quarter and full year 2013 forecast and benchmark commodity pricing information for EOG Resources, Inc., which information is incorporated herein by reference. This information shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

99.1 Press Release of EOG Resources, Inc. dated February 13, 2013 (including the accompanying first quarter and full year 2013 forecast and benchmark commodity pricing information).

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 hereunto duly authorized.

EOG RESOURCES, INC.
(Registrant)

Date: February 13, 2013	By:	/s/ TIMOTHY K. DRIGGERS Timothy K. Driggers Vice President and Chief Financial Officer (Principal Financial Officer and Duly Authorized Officer)

EXHIBIT INDEX

Exhibit No.	**Description**
99.1	Press Release of EOG Resources, Inc. dated February 13, 2013 (including the accompanying first quarter and full year 2013 forecast and benchmark commodity pricing information).

EXHIBIT 99.1

News Release

For Further Information Contact:

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EOG Resources Reports Outstanding 2012 Results; Increases Eagle Ford and Leonard Reserve Potential; Announces New Texas Delaware Basin Wolfcamp Play; Raises Common Stock Dividend by 10 Percent

- Achieves 39 Percent Year-Over-Year Total Company Crude Oil and Condensate Growth and 37 Percent Total Liquids Growth
- Reports 10 Percent Total Company Production Growth
- Delivers Strong Year-Over-Year Growth in Non-GAAP Earnings Per Share, Adjusted EBITDAX and Discretionary Cash Flow
- Increases Eagle Ford Potential Recoverable Reserve Estimate by 600 MMBoe to 2.2 BnBoe, Net to EOG
- Highlights Record Eagle Ford Oil Well
- Announces New Wolfcamp Shale Play in Delaware Basin and Increases Leonard Shale Potential Reserves with Total Combined Delaware Basin Potential Reserves of 1.35 BnBoe, Net to EOG
- Realizes Improvements in Bakken/Three Forks Operations
- Delivers 268 Percent Reserve Replacement at Attractive Finding Costs, Excluding Price-Related Reserve Revisions
- Raises Common Stock Dividend for 14^{th} Time in 14 Years

FOR IMMEDIATE RELEASE: Wednesday, February 13, 2013

HOUSTON – EOG Resources, Inc. (EOG) today reported full year 2012 net income of $570.3 million, or $2.11 per share, as compared to $1,091.1 million, or $4.10 per share, for the full year 2011. For the fourth quarter 2012, EOG reported a net loss of $505.0 million, or $1.88 per share. This compares to fourth quarter 2011 net income of $120.7 million, or $0.45 per share.

Adjusted non-GAAP net income for the full year 2012 was $1,535.6 million, or $5.67 per share, and for the full year 2011 was $1,008.5 million, or $3.79 per share. Adjusted non-GAAP net income for the fourth quarter 2012 was $437.0 million, or $1.61 per share, and for the fourth quarter 2011 was $309.0 million, or $1.15 per share.

Consistent with some analysts' practice of matching realizations to settlement months and making certain other adjustments in order to exclude one-time items, the results for the fourth quarter 2012 include $849.4 million, net of tax ($3.13 per share) of impairments of certain Canadian natural gas assets, net losses on asset dispositions of $35.6 million, net of tax ($0.13 per share) and a previously disclosed non-cash net gain of $66.4 million ($42.5 million after tax, or $0.16 per share) on the mark-to-market of financial commodity derivative contracts. During the fourth quarter, the net cash inflow related to financial commodity derivative contracts was $155.5 million ($99.5 million after tax, or $0.37 per share). (Please refer to the attached tables for the reconciliation of adjusted non-GAAP net income to GAAP net income/loss.)

Reflecting EOG's higher revenue and production weighting to crude oil for the full year 2012, adjusted non-GAAP net income per share increased 50 percent, adjusted EBITDAX increased 26 percent and discretionary cash flow increased 26 percent as compared to 2011. (Please refer to the attached tables for the reconciliation of adjusted non-GAAP net income per share to GAAP net income per share, adjusted EBITDAX (non-GAAP) to income before interest expense and income taxes (GAAP) and non-GAAP discretionary cash flow to net cash provided by operating activities (GAAP).)

In the United States, crude oil and condensate production increased 46 percent for the full year 2012 compared to the prior year. Total United States liquids (crude oil, condensate and natural gas liquids) production increased 42 percent for full year 2012 over the same period a year ago. On a total company basis, total crude oil and condensate production increased 39 percent and total liquids production increased 37 percent for the full year compared to 2011. Overall total company production increased 10 percent year-over-year.

"We accomplished all of EOG's 2012 goals. We generated high margin organic crude oil production growth and delivered excellent year-over-year increases in EOG's financial metrics. We maintained our net-debt-to-total cap ratio below 30 percent and recorded strong crude oil reserve replacement rates at attractive finding costs," said Mark G. Papa, Chairman and Chief Executive Officer. "In addition, we added the Delaware Basin Wolfcamp, a promising new liquids resource play to our portfolio and significantly increased the potential recoverable reserves of our largest and highest rate of return asset, the South Texas Eagle Ford. These add high-value inventory to EOG's already prolific asset base."

Operational Highlights

EOG's stellar crude oil production in 2012 was primarily driven by drilling and completion activity in the Eagle Ford where the company drilled and completed 305 net wells, operating an average of 23 drilling rigs. In the North Dakota Bakken/Three Forks, positive results from downspaced drilling tests, together with significant modifications in drilling and completion techniques, further boosted EOG's crude oil production growth. Breakthroughs in geologic modeling in the Leonard/Wolfcamp horizontal shale plays in southeastern New Mexico and West Texas also contributed to EOG's excellent performance.

EOG made strides in increasing the amount of crude oil recoverable from both its Eagle Ford and Bakken resources by testing various drilling densities and further refining completion practices. In the Eagle Ford, EOG increased the estimated recoverable potential reserves by 38 percent from 1.6 billion barrels of oil equivalent (BnBoe) to 2.2 BnBoe, net to EOG. Numerous spacing pilots across EOG's 569,000 net acres in the crude oil window point to optimal resource development on 40-acre well spacing in the east and 65 acres in the west. At current activity levels, EOG has a 12-year Eagle Ford drilling inventory.

The revised Eagle Ford reserve potential is indicative of an estimated 8 percent recovery of the estimated 26.4 net BnBoe in place on EOG's acreage. Since discovering the Eagle Ford in 2010, EOG has raised the overall estimated captured reserve potential from 900 MMBoe (million barrels of oil equivalent) to 2.2 BnBoe, net to EOG.

EOG's best Eagle Ford well to date is the Burrow Unit #2H, which had an initial production rate of 6,330 barrels of oil per day (Bopd) with 713 barrels per day (Bpd) of natural gas liquids (NGLs) and 4.1 million cubic feet per day (MMcfd) of natural gas. Offsetting the Burrow Unit #2H, the Burrow Unit #1H was completed to sales at a maximum rate of 5,424 Bopd with 600 Bpd of NGLs and 3.5 MMcfd of natural gas. Two other prolific wells, the Boothe Unit #1H and #2H, began initial production at 5,380 and 3,810 Bopd with 625 and 525 Bpd of NGLs and 3.6 and 3.0 MMcfd of natural gas, respectively. EOG has 100 percent working interest in these Gonzales County wells.

In McMullen County, southwest of EOG's Gonzales County sweet spot, the Naylor Jones Unit 59 East #1H and West #4H had initial peak production rates of 1,670 and 1,150 Bopd with 225 and 138 Bpd of NGLs and 1.3 and 0.8 MMcfd of natural gas, respectively. EOG has 100 percent working interest in these wells that were completed in early January 2013.

"The Eagle Ford's potential reserves of 2.2 billion barrels of oil equivalent represent the largest domestic crude oil find net to one company in 40 years. Not only is 600 million net barrels a meaningful increase, this onshore U.S. oil field is readily accessible to premium markets," Papa said. "With both the technical acumen and high-quality assets, EOG is at the forefront in developing this world-class shale oil resource."

Over the course of 2012, EOG's North Dakota wells showed marked productivity improvement following the implementation of new completion techniques. On its 90,000 net acre Bakken Core, EOG confirmed that 320-acre well spacing is economically sound, and it is very encouraged by 160-acre results. Recent downspaced tests reflect a gain of approximately 30 percent to 70 percent in cumulative production over earlier wells drilled in the field. The Fertile 51-0410H, in which EOG has a 94 percent working interest, had a maximum initial production rate of 1,800 Bopd with 850 thousand cubic feet per day (Mcfd) of rich natural gas. The first 160-acre spaced wells in the Core area, the Wayzetta 022-1509H and 149-1509H, had maximum rates of 1,185 and 1,265 Bopd, respectively. EOG has 68 percent working interest in these wells.

Southwest of the Bakken Core in the Antelope Extension, the Hawkeye 01-2501H and 102-2501H were completed to sales in early January 2013. These McKenzie County wells, in which EOG has 75 percent working interest, were turned to sales at 2,445 and 2,945 Bopd, respectively. In the Stateline area near the North Dakota/Montana border, the Garden Coulee 001-1410H had an initial production rate of 1,415 Bopd with 1,260 Mcfd of rich natural gas. EOG has a 74 percent working interest in this Williams County, N.D., well.

On the Texas side of the Delaware Basin, EOG confirmed a new shale play with the completion of two horizontal Wolfcamp wells on its 114,000 net acre position. In Reeves County, the Harrison Ranch #56-1002H and #56-1001H tested at rates of 377 Bopd with 602 Bpd of NGLs and 3.9 MMcfd of natural gas and 635 Bopd with 480 Bpd of NGLs and 3.1 MMcfd of natural gas, respectively. EOG has 100 percent working interest in these wells. Based on the geologic characteristics of the formation and the potential to drill multiple laterals combined with data from over 200 previously drilled vertical wells on EOG's acreage, estimated net potential reserves are approximately 800 MMBoe, a mix of crude oil and liquids-rich natural gas.

In southeastern New Mexico, the overall economics and size of EOG's horizontal Delaware Basin Leonard Shale play improved last year due to strong well results and decreased drilling costs. The Vaca 14 Fed #6H was completed in Lea County at an initial rate of 1,290 Bopd with 255 Bpd of NGLs and 1.4 MMcfd of natural gas. EOG has 100 percent working interest in this well. EOG has increased the total net reserve potential on its 73,000 net acres from 65 MMBoe to 550 MMBoe, predicated on better well results and a 50 percent crude oil yield. Total potential reserves on EOG's Delaware Basin horizontal Wolfcamp and Leonard Shale plays are estimated to be 1.35 BnBoe, net.

During 2012, EOG secured premium pricing for some of its Bakken, Eagle Ford and Permian Basin crude oil by expanding its innovative crude-by-rail operations. Commissioned in April 2012, a crude oil unloading terminal at St. James, La., enabled EOG to achieve average domestic crude oil realizations exceeding benchmark West Texas Intermediate indices.

Reserves

EOG's total company net proved reserves were 1,811 MMBoe at December 31, 2012. Total company net proved developed reserves decreased 2 percent, and total North American net proved developed reserves were approximately flat with the previous year, excluding the impact of property dispositions. Total company net proved undeveloped reserves decreased 15 percent year over year due to low natural gas prices in 2012 that caused essentially all of the previously booked proved undeveloped reserves in EOG's North American dry gas properties to be written off. Total proved liquids reserves increased 37 percent year-over-year, comprising 56 percent of total company proved reserves at December 31, 2012.

In 2012:

- Total reserve replacement from all sources – the ratio of net reserve additions from drilling, acquisitions, total revisions and dispositions to total production – was 268 percent at a total reserve replacement cost of $12.60 per barrel of oil equivalent (Boe), based on exploration and development expenditures of $6,921 million and excluding price-related revisions. (For the calculation of total reserve replacement and total reserve replacement costs, please refer to the attached tables.)
- Total liquids reserve replacement from all sources – the ratio of net reserve additions from drilling, acquisitions, total revisions and dispositions to total production – was 452 percent. (For the calculation of total liquids reserve replacement, please refer to the attached tables.)

- Reserve replacement from drilling – the ratio of extensions, discoveries and other additions to total production – was 238 percent. Crude oil reserve replacement from drilling in the United States was 442 percent. (For the calculation of reserve replacement from drilling, please refer to the attached tables.)
- In the United States, total reserve replacement from all sources, excluding price-related revisions, was 326 percent at a reserve replacement cost of $11.82 per Boe based on exploration and development expenditures of $6,362 million. (For the calculation of United States total reserve replacement and total reserve replacement costs, please refer to the attached tables.) In the United States, 80 percent of the reserve additions were liquids.

For the 25th consecutive year, internal reserve estimates were within 5 percent of those prepared by the independent reserve engineering firm of DeGolyer and MacNaughton (D&M). For 2012, D&M prepared a complete independent engineering analysis of properties comprising 87 percent of EOG's proved reserves on a Boe basis.

Capital Structure

EOG's 2012 total cash capital expenditure program was approximately $7.5 billion. (Please refer to the attached tables for the reconciliation of total expenditures (GAAP) to total cash expenditures (non-GAAP).) Through year-end 2012, EOG's cash proceeds from asset sales were approximately $1.3 billion.

At December 31, 2012, EOG's total debt outstanding was $6,312 million for a debt-to-total capitalization ratio of 32 percent. Taking into account cash on the balance sheet of $876 million at the end of the fourth quarter, EOG's net debt was $5,436 million for a net debt-to-total capitalization ratio of 29 percent. (Please refer to the attached tables for the reconciliation of net debt (non-GAAP) to current and long-term debt (GAAP) and the reconciliation of net debt-to-total capitalization ratio (non-GAAP) to debt-to-total capitalization ratio (GAAP).)

"2012 marked a turning point for EOG. We continued to develop our key crude oil assets while locking up core natural gas and Combo acreage in the Barnett, Leonard and Wolfcamp plays for the long term. In addition, we exited the Kitimat LNG project," Papa said.

2013 Plans

EOG is targeting total company crude oil production growth of 28 percent with a 23 percent increase in total liquids production in 2013. In North America, natural gas production is expected to decrease 15 percent from 2012. EOG is continuing to de-emphasize natural gas drilling in a weak price environment. Driven by high margin, domestic crude oil production, overall EOG's total company production is expected to increase 4 percent over 2012.

Estimated exploration and development expenditures for 2013 are expected to range from $7.0 to $7.2 billion, including production facilities and midstream expenditures, and excluding acquisitions. Overall asset sales are expected to be approximately $550 million, of which $466 million has closed to date.

In 2013, EOG plans an active crude oil and liquids exploration program focusing on increasing recovery of hydrocarbons in existing plays and pursuing new greenfield opportunities. The majority of EOG's capital expenditures will be directed toward its two key crude oil assets, the Eagle Ford and Bakken/Three Forks. The Eagle Ford, where EOG estimates it will drill and complete approximately 400 net wells, is expected to contribute the largest share of company production growth in 2013. In the North Dakota Bakken Core and Antelope Extension Bakken/Three Forks, plans are to test additional downspaced drilling patterns. In its southeastern New Mexico horizontal Leonard/West Texas Wolfcamp Shale plays, EOG anticipates operating a moderate drilling program in 2013. Drilling activity in the new Delaware Basin Wolfcamp play is expected to ramp up over the next two years to achieve significant production growth for EOG beginning in 2015. Very minimal dry gas drilling activity is expected in 2013.

"EOG's demonstrated ability to organically grow crude oil volumes should lead to strong 2013 returns," Papa said. "Until other commodity prices strengthen, we are directing EOG's capex dollars almost exclusively toward crude oil exploration and development. Leading with our Eagle Ford and North Dakota operations, EOG is well positioned to achieve its game plan, while identifying strategic marketing advances that will further strengthen our position. With the most attractive drilling program in our history, EOG has the critical assets in place to make 2013 another outstanding year."

2013 Hedging

For the period January 1 through June 30, 2013, EOG has crude oil financial price swap contracts in place for an average of 105,000 Bopd at a weighted average price of $99.23 per barrel, excluding unexercised options. For the period July 1 through December 31, 2013, EOG has an average of 93,000 Bopd hedged at a weighted average price of $98.44 per barrel, excluding unexercised options.

Despite very minimal dry natural gas drilling activity planned for 2013, EOG has financial price swap contracts in place for 150,000 million British thermal units per day of natural gas at a weighted average price of $4.79 per million British thermal units, excluding unexercised options for the calendar year. (For a comprehensive summary of EOG's crude oil and natural gas derivative contracts, please refer to the attached tables.)

Dividend Increase

Following an increase in the common stock dividend in 2012, EOG's Board of Directors has again increased the cash dividend on the common stock. Effective with the dividend payable on April 30, 2013, to holders of record as of April 16, 2013, the quarterly dividend on the common stock will be $0.1875 per share, an increase of 10 percent over the previous indicated annual rate. The indicated annual rate of $0.75 per share reflects the 14th increase in 14 years.

Conference Call Scheduled for Thursday, February 14, 2013

EOG's fourth quarter and full year 2012 results conference call will be available via live audio webcast at 8 a.m. Central time (9 a.m. Eastern time) on Thursday, February 14, 2013. To listen, log on to www.eogresources.com. The webcast will be archived on EOG's website through Thursday, February 28, 2013.

EOG Resources, Inc. 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 Resources, Inc. is listed on the New York Stock Exchange and is traded under the ticker symbol "EOG."

This press release 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, generate income or cash flows or pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known 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 and condensate, natural gas liquids, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, and to produce reserves and achieve anticipated production levels from, its existing and future crude oil and natural gas

exploration and development projects, given the risks and uncertainties and capital expenditure requirements inherent in drilling, completing and operating crude oil and natural gas wells and the potential for interruptions of development and production, whether involuntary or intentional as a result of market or other conditions;

- the extent to which EOG is successful in its efforts to market its crude oil, natural gas and related commodity production;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;
- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- competition in the oil and gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation of production, gathering, processing, compression and transportation facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- political developments around the world, including in the areas in which EOG operates;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors," on pages 15 through 23 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2011 and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

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.

Effective January 1, 2010, the United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose not only "proved" reserves (i.e., quantities of oil and gas that are estimated to be recoverable with a high degree of confidence), but also "probable" reserves (i.e., quantities of oil and gas that are as likely as not to be recovered) as well as "possible" reserves (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). As noted above, statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserve estimates provided in this press release that are not specifically designated as being estimates of proved reserves may include "potential" reserves and/or other estimated reserves not necessarily calculated in accordance with, or contemplated by, the SEC's latest reserve reporting guidelines. Investors are urged to consider closely the disclosure in EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2011, available from EOG at P.O. Box 4362, Houston, Texas 77210-4362 (Attn: Investor Relations). You can also obtain this report from the SEC by calling 1-800-SEC-0330 or from the SEC's website at www.sec.gov. In addition, reconciliation and calculation schedules for non-GAAP financial measures can be found on the EOG website at www.eogresources.com.

EOG RESOURCES, INC.
FINANCIAL REPORT
(Unaudited; in millions, except per share data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	**2011**	**2012**	**2011**
Net Operating Revenues	$ 3,011.8	$ 2,773.0	$ 11,682.6	$ 10,126.1
Net Income (Loss)	$ (505.0)	$ 120.7	$ 570.3	$ 1,091.1
Net Income (Loss) Per Share				
Basic	$ (1.88)	$ 0.45	$ 2.13	$ 4.15
Diluted	$ (1.88)	$ 0.45	$ 2.11	$ 4.10
Average Number of Common Shares				
Basic	268.9	266.3	267.6	262.7
Diluted	268.9	269.5	270.8	266.3

SUMMARY INCOME STATEMENTS
(Unaudited; in thousands, except per share data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	**2011**	**2012**	**2011**
Net Operating Revenues				
Crude Oil and Condensate	$ 1,460,684	$ 1,189,250	$ 5,659,437	$ 3,838,284
Natural Gas Liquids	208,493	240,260	727,177	779,364
Natural Gas	418,329	479,825	1,571,762	2,240,540
Gains on Mark-to-Market Commodity Derivative Contracts	66,416	145,514	393,744	626,053
Gathering, Processing and Marketing	903,404	654,489	3,096,694	2,115,792
Gains (Losses) on Asset Dispositions, Net	(55,474)	49,928	192,660	492,909
Other, Net	9,959	13,749	41,162	33,173
Total	3,011,811	2,773,015	11,682,636	10,126,115
Operating Expenses				
Lease and Well	234,349	261,244	1,000,052	941,954
Transportation Costs	169,789	122,046	601,431	430,322
Gathering and Processing Costs	25,542	25,283	97,945	80,727
Exploration Costs	48,660	31,042	185,569	171,658
Dry Hole Costs	1,965	5,999	14,970	53,230
Impairments	1,020,496	499,624	1,270,735	1,031,037
Marketing Costs	880,451	644,687	3,035,494	2,072,137
Depreciation, Depletion and Amortization	786,344	693,527	3,169,703	2,516,381
General and Administrative	86,679	85,108	331,545	304,811
Taxes Other Than Income	135,597	101,880	495,395	410,549
Total	3,389,872	2,470,440	10,202,839	8,012,806
Operating Income (Loss)	(378,061)	302,575	1,479,797	2,113,309
Other Income (Expense), Net	(8,407)	(4,352)	14,495	6,853
Income (Loss) Before Interest Expense and Income Taxes	(386,468)	298,223	1,494,292	2,120,162
Interest Expense, Net	59,354	56,591	213,552	210,363
Income (Loss) Before Income Taxes	(445,822)	241,632	1,280,740	1,909,799
Income Tax Provision	59,177	120,934	710,461	818,676
Net Income (Loss)	$ (504,999)	$ 120,698	$ 570,279	$ 1,091,123
Dividends Declared per Common Share	$ 0.17	$ 0.16	$ 0.68	$ 0.64

EOG RESOURCES, INC.
OPERATING HIGHLIGHTS
(Unaudited)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	**2011**	**2012**	**2011**
Wellhead Volumes and Prices				
Crude Oil and Condensate Volumes (MBbld) (A)				
United States	154.1	124.8	149.3	102.0
Canada	7.5	7.6	7.0	7.9
Trinidad	1.0	2.8	1.5	3.4
Other International (B)	0.1	0.1	0.1	0.1
Total	162.7	135.3	157.9	113.4
Average Crude Oil and Condensate Prices ($/Bbl) (C)				
United States	$ 98.72	$ 96.33	$ 98.38	$ 92.92
Canada	85.59	89.32	86.08	91.92
Trinidad	83.93	87.02	92.26	90.62
Other International (B)	87.34	103.46	89.57	100.11
Composite	98.02	95.75	97.77	92.79
Natural Gas Liquids Volumes (MBbld) (A)				
United States	57.0	49.6	55.1	41.5
Canada	0.8	1.1	0.8	0.9
Total	57.8	50.7	55.9	42.4
Average Natural Gas Liquids Prices ($/Bbl) (C)				
United States	$ 35.36	$ 51.58	$ 35.41	$ 50.37
Canada	42.50	49.16	44.13	52.69
Composite	35.45	51.53	35.54	50.41
Natural Gas Volumes (MMcfd) (A)				
United States	981	1,085	1,034	1,113
Canada	84	124	95	132
Trinidad	335	313	378	344
Other International (B)	8	11	9	13
Total	1,408	1,533	1,516	1,602
Average Natural Gas Prices ($/Mcf) (C)				
United States	$ 2.93	$ 3.27	$ 2.51	$ 3.92
Canada	2.98	3.14	2.49	3.71
Trinidad	4.12	3.87	3.72	3.53
Other International (B)	5.75	5.70	5.71	5.62
Composite	3.23	3.40	2.83	3.83
Crude Oil Equivalent Volumes (MBoed) (D)				
United States	374.6	355.3	376.6	329.1
Canada	22.3	29.3	23.6	30.7
Trinidad	56.8	54.9	64.5	60.7
Other International (B)	1.4	2.0	1.7	2.2
Total	455.1	441.5	466.4	422.7
Total MMBoe (D)	41.9	40.6	170.7	154.3

(A) Thousand barrels per day or million cubic feet per day, as applicable.
(B) Other International includes EOG's United Kingdom, China and Argentina operations.
(C) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments.
(D) 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.

EOG RESOURCES, INC.
SUMMARY BALANCE SHEETS
(Unaudited; in thousands, except share data)

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 876,435	$ 615,726
Accounts Receivable, Net	1,656,618	1,451,227
Inventories	683,187	590,594
Assets from Price Risk Management Activities	166,135	450,730
Income Taxes Receivable	29,163	26,609
Other	178,346	119,052
Total	3,589,884	3,253,938
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	38,126,298	33,664,435
Other Property, Plant and Equipment	2,740,619	2,149,989
Total Property, Plant and Equipment	40,866,917	35,814,424
Less: Accumulated Depreciation, Depletion and Amortization	(17,529,236)	(14,525,600)
Total Property, Plant and Equipment, Net	23,337,681	21,288,824
Other Assets	409,013	296,035
Total Assets	$ 27,336,578	$ 24,838,797
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 2,078,948	$ 2,033,615
Accrued Taxes Payable	162,083	147,105
Dividends Payable	45,802	42,578
Liabilities from Price Risk Management Activities	7,617	-
Deferred Income Taxes	22,838	135,989
Current Portion of Long-Term Debt	406,579	-
Other	200,191	163,032
Total	2,924,058	2,522,319
Long-Term Debt	5,905,602	5,009,166
Other Liabilities	894,758	799,189
Deferred Income Taxes	4,327,396	3,867,219
Commitments and Contingencies		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 271,958,495 Shares and 269,323,084 Shares Issued at December 31, 2012 and 2011, respectively	202,720	202,693
Additional Paid in Capital	2,500,340	2,272,052
Accumulated Other Comprehensive Income	439,895	401,746
Retained Earnings	10,175,631	9,789,345
Common Stock Held in Treasury, 326,264 Shares and 303,633 Shares at December 31, 2012 and 2011, respectively	(33,822)	(24,932)
Total Stockholders' Equity	13,284,764	12,640,904
Total Liabilities and Stockholders' Equity	$ 27,336,578	$ 24,838,797

EOG RESOURCES, INC.
SUMMARY STATEMENTS OF CASH FLOWS
(Unaudited; in thousands)

	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011
Cash Flows from Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 570,279	$ 1,091,123
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	3,169,703	2,516,381
Impairments	1,270,735	1,031,037
Stock-Based Compensation Expenses	127,778	128,345
Deferred Income Taxes	292,938	499,300
Gains on Asset Dispositions, Net	(192,660)	(492,909)
Other, Net	672	15,139
Dry Hole Costs	14,970	53,230
Mark-to-Market Commodity Derivative Contracts		
Total Gains	(393,744)	(626,053)
Realized Gains	711,479	180,701
Excess Tax Benefits from Stock-Based Compensation	(67,035)	-
Other, Net	14,411	26,454
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(178,683)	(339,780)
Inventories	(156,762)	(176,623)
Accounts Payable	(17,150)	351,087
Accrued Taxes Payable	78,094	92,589
Other Assets	(118,520)	(23,625)
Other Liabilities	36,114	14,986
Changes in Components of Working Capital Associated with Investing and Financing Activities	74,158	237,028
Net Cash Provided by Operating Activities	5,236,777	4,578,410
Investing Cash Flows		
Additions to Oil and Gas Properties	(6,735,316)	(6,294,397)
Additions to Other Property, Plant and Equipment	(619,800)	(656,415)
Proceeds from Sales of Assets	1,309,776	1,433,137
Changes in Components of Working Capital Associated with Investing Activities	(73,923)	(237,267)
Net Cash Used in Investing Activities	(6,119,263)	(5,754,942)
Financing Cash Flows		
Common Stock Sold	-	1,388,265
Long-Term Debt Borrowings	1,234,138	-
Long-Term Debt Repayments	-	(220,000)
Dividends Paid	(181,080)	(167,169)
Excess Tax Benefits from Stock-Based Compensation	67,035	-
Treasury Stock Purchased	(58,592)	(23,922)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	82,887	35,913
Debt Issuance Costs	(1,578)	(4,787)
Repayment of Capital Lease Obligation	(2,824)	-
Other, Net	(235)	239
Net Cash Provided by Financing Activities	1,139,751	1,008,539
Effect of Exchange Rate Changes on Cash	3,444	(5,134)
Increase (Decrease) in Cash and Cash Equivalents	260,709	(173,127)
Cash and Cash Equivalents at Beginning of Period	615,726	788,853
Cash and Cash Equivalents at End of Period	$ 876,435	$ 615,726

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF ADJUSTED NET INCOME (NON-GAAP)
TO NET INCOME (LOSS) (GAAP)
(Unaudited; in thousands, except per share data)

The following chart adjusts the three-month and twelve-month periods ended December 31, 2012 and 2011 reported Net Income (Loss) (GAAP) to reflect actual net cash realized from financial commodity price transactions by eliminating the unrealized mark-to-market gains from these transactions, to add back charges related to impairments of certain of EOG's North American assets in 2012 and 2011, to add back the write-off of fees associated with revolving credit facilities cancelled in connection with the establishment of a new revolving credit facility in the fourth quarter of 2011 and to eliminate the net gains (losses) on asset dispositions primarily in North America in 2012 and 2011. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported company earnings to match realizations to production settlement months and make certain other adjustments to exclude non-recurring items. EOG management uses this information for comparative purposes within the industry.

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	2011	2012	2011
Reported Net Income (Loss) (GAAP)	$ (504,999)	$ 120,698	$ 570,279	$ 1,091,123
Mark-to-Market (MTM) Commodity Derivative Contracts Impact				
Total Gains	(66,416)	(145,514)	(393,744)	(626,053)
Realized Gains	155,533	96,936	711,479	180,701
Subtotal	89,117	(48,578)	317,735	(445,352)
After-Tax MTM Impact	57,058	(31,101)	203,430	(285,136)
Add: Impairments of Certain North American Assets, Net of Tax	849,371	249,084	887,946	516,198
Add: Write-off of Fees Associated with Revolving Credit Facilities, Net of Tax	-	3,656	-	3,656
Less: Net (Gains) Losses on Asset Dispositions, Net of Tax	35,599	(33,337)	(126,053)	(317,342)
Adjusted Net Income (Non-GAAP)	$ 437,029	$ 309,000	$ 1,535,602	$ 1,008,499
Net Income (Loss) Per Share (GAAP)				
Basic	$ (1.88)	$ 0.45	$ 2.13	$ 4.15
Diluted	$ (1.88)	$ 0.45	$ 2.11	$ 4.10
Adjusted Net Income Per Share (Non-GAAP)				
Basic	$ 1.62	$ 1.16	$ 5.74	$ 3.84
Diluted	$ 1.61	$ 1.15	$ 5.67 **(a)**	$ 3.79 **(b)**
Percentage Increase - [(a) - (b)] / (b)			**50%**	
Average Number of Common Shares (GAAP)				
Basic	268,941	266,277	267,577	262,735
Diluted	268,941	269,524	270,762	266,268
Average Number of Shares (Non-GAAP)				
Basic	268,941	266,277	267,577	262,735
Diluted	271,921	269,524	270,762	266,268

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF DISCRETIONARY CASH FLOW (NON-GAAP)
TO NET CASH PROVIDED BY OPERATING ACTIVITIES (GAAP)
(Unaudited; in thousands)

The following chart reconciles the three-month and twelve-month periods ended December 31, 2012 and 2011 Net Cash Provided by Operating Activities (GAAP) to Discretionary Cash Flow (Non-GAAP). EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust Net Cash Provided by Operating Activities for Exploration Costs (excluding Stock-Based Compensation Expenses), Excess Tax Benefits from Stock-Based Compensation, Changes in Components of Working Capital and Other Assets and Liabilities, and Changes in Components of Working Capital Associated with Investing and Financing Activities. EOG management uses this information for comparative purposes within the industry.

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	2011	2012	2011
Net Cash Provided by Operating Activities (GAAP)	$ 1,227,187	$ 1,236,887	$ 5,236,777	$ 4,578,410
Adjustments				
Exploration Costs (excluding Stock-Based Compensation Expenses)	42,619	24,715	159,182	145,881
Excess Tax Benefits from Stock-Based Compensation	17,609	-	67,035	-
Changes in Components of Working Capital and Other Assets and Liabilities				
Accounts Receivable	66,509	210,815	178,683	339,780
Inventories	1,996	9,012	156,762	176,623
Accounts Payable	100,832	(105,702)	17,150	(351,087)
Accrued Taxes Payable	(35,303)	8,650	(78,094)	(92,589)
Other Assets	(1,565)	(4,975)	118,520	23,625
Other Liabilities	3,757	22,036	(36,114)	(14,986)
Changes in Components of Working Capital Associated with Investing and Financing Activities	13,550	(103,801)	(74,158)	(237,028)
Discretionary Cash Flow (Non-GAAP)	$ 1,437,191	$ 1,297,637	$ 5,745,743 **(a)**	$ 4,568,629 **(b)**
Percentage Increase - [(a) - (b)] / (b)			**26%**	

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF ADJUSTED EARNINGS BEFORE INTEREST EXPENSE, INCOME TAXES, DEPRECIATION, DEPLETION AND AMORTIZATION, EXPLORATION COSTS, DRY HOLE COSTS, IMPAIRMENTS AND ADDITIONAL ITEMS (ADJUSTED EBITDAX) (NON-GAAP) TO INCOME (LOSS) BEFORE INTEREST EXPENSE AND INCOME TAXES (GAAP)
(Unaudited; in thousands)

The following chart adjusts the three-month and twelve-month periods ended December 31, 2012 and 2011 reported Income (Loss) Before Interest Expense and Income Taxes (GAAP) to Earnings Before Interest Expense, Income Taxes, Depreciation, Depletion and Amortization, Exploration Costs, Dry Hole Costs and Impairments (EBITDAX) (Non-GAAP) and further adjusts such amount to reflect actual net cash realized from financial commodity derivative transactions by eliminating the unrealized mark-to-market (MTM) gains from these transactions and to eliminate the net gains (losses) on asset dispositions primarily in North America in 2012 and 2011. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported Income (Loss) Before Interest Expense and Income Taxes (GAAP) to add back Depreciation, Depletion and Amortization, Exploration Costs, Dry Hole Costs and Impairments and further adjust such amount to match realizations to production settlement months and make certain other adjustments to exclude non-recurring items. EOG management uses this information for comparative purposes within the industry.

	Three Months Ended December 31,		Twelve Months Ended December 31,		
	2012	**2011**	**2012**	**2011**	
Income (Loss) Before Interest Expense and Income Taxes (GAAP)	$ (386,468)	$ 298,223	$ 1,494,292	$ 2,120,162	
Adjustments:					
Depreciation, Depletion and Amortization	786,344	693,527	3,169,703	2,516,381	
Exploration Costs	48,660	31,042	185,569	171,658	
Dry Hole Costs	1,965	5,999	14,970	53,230	
Impairments	1,020,496	499,624	1,270,735	1,031,037	
EBITDAX (Non-GAAP)	1,470,997	1,528,415	6,135,269	5,892,468	
Total Gains on MTM Commodity Derivative Contracts	(66,416)	(145,514)	(393,744)	(626,053)	
Realized Gains on MTM Commodity Derivative Contracts	155,533	96,936	711,479	180,701	
Net Losses (Gains) on Asset Dispositions	55,474	(49,928)	(192,660)	(492,909)	
Adjusted EBITDAX (Non-GAAP)	$ 1,615,588	$ 1,429,909	$ 6,260,344 **(a)**	$ 4,954,207	**(b)**
Percentage Increase - [(a) - (b)] / (b)			**26%**		

EOG RESOURCES, INC.
CRUDE OIL AND NATURAL GAS FINANCIAL
COMMODITY DERIVATIVE CONTRACTS

Presented below is a comprehensive summary of EOG's crude oil and natural gas derivative contracts at February 13, 2013, with notional volumes expressed in Bbld and MMBtud and prices expressed in $/Bbl and $/MMBtu. EOG accounts for financial commodity derivative contracts using the mark-to-market accounting method.

CRUDE OIL DERIVATIVE CONTRACTS

	Volume [1] (Bbld)	Weighted Average Price ($/Bbl)
2013		
January 2013 (closed)	101,000	$99.29
February 1, 2013 through April 30, 2013	109,000	99.17
May 1, 2013 through June 30, 2013	101,000	99.29
July 1, 2013 through December 31, 2013	93,000	98.44

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional three-month or six-month periods. Options covering a notional volume of 8,000 Bbld are exercisable on April 30, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 8,000 Bbld at an average price of $97.66 per barrel for the period May 1, 2013 through July 31, 2013. Options covering a notional volume of 62,000 Bbld are exercisable on June 28, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 62,000 Bbld at an average price of $100.24 per barrel for the period July 1, 2013 through December 31, 2013. Options covering a notional volume of 54,000 Bbld are exercisable on December 31, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 54,000 Bbld at an average price of $98.91 per barrel for the period January 1, 2014 through June 30, 2014.

NATURAL GAS DERIVATIVE CONTRACTS

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2013 [2]		
January 1, 2013 through February 28, 2013 (closed)	150,000	$4.79
March 1, 2013 through December 31, 2013	150,000	4.79
2014 [3]		

(2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 150,000 MMBtud at an average price of $4.79 per MMBtu for the period from March 1, 2013 through December 31, 2013.

(3) In July 2012, EOG settled its natural gas financial price swap contracts for the period January 1, 2014 through December 31, 2014. In connection with these contracts, the counterparties retain an option of entering into derivative 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 derivative contracts will increase by 150,000 MMBtud at an average price of $4.79 per MMBtu for each month of 2014.

Bbld	Barrels per day.
$/Bbl	Dollars per barrel.
MMBtud	Million British thermal units per day.
$/MMBtu	Dollars per million British thermal units.
MMBtu	Million British thermal units.

EOG RESOURCES, INC.

QUANTITATIVE RECONCILIATION OF NET DEBT (NON-GAAP) AND TOTAL CAPITALIZATION (NON-GAAP) AS USED IN THE CALCULATION OF THE NET DEBT-TO-TOTAL CAPITALIZATION RATIO (NON-GAAP) TO CURRENT AND LONG-TERM DEBT (GAAP) AND TOTAL CAPITALIZATION (GAAP)

(Unaudited; in millions, except ratio data)

The following chart reconciles Current and Long-Term Debt (GAAP) to Net Debt (Non-GAAP) and Total Capitalization (GAAP) to Total Capitalization (Non-GAAP), as used in the Net Debt-to-Total Capitalization ratio calculation. A portion of the cash is associated with international subsidiaries; tax considerations may impact debt paydown. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who utilize Net Debt and Total Capitalization (Non-GAAP) in their Net Debt-to-Total Capitalization ratio calculation. EOG management uses this information for comparative purposes within the industry.

	December 31, 2012
Total Stockholders' Equity - (a)	$ 13,285
Current and Long-Term Debt - (b)	6,312
Less: Cash	(876)
Net Debt (Non-GAAP) - (c)	5,436
Total Capitalization (GAAP) - (a) + (b)	$ 19,597
Total Capitalization (Non-GAAP) - (a) + (c)	$ 18,721
Debt-to-Total Capitalization (GAAP) - (b) / [(a) + (b)]	**32%**
Net Debt-to-Total Capitalization (Non-GAAP) - (c) / [(a) + (c)]	**29%**

EOG RESOURCES, INC.
RESERVES SUPPLEMENTAL DATA
(Unaudited)

2012 NET PROVED RESERVES RECONCILIATION SUMMARY

	United States	Canada	North America	Trinidad	Other Int'l	Total Int'l	Total
CRUDE OIL & CONDENSATE (MMBbls)							
Beginning Reserves	495.3	18.6	513.9	3.5	0.1	3.6	517.5
Revisions	4.1	(2.5)	1.6	0.1	-	0.1	1.7
Purchases in place	1.0	-	1.0	-	-	-	1.0
Extensions, discoveries and other additions	241.2	5.7	246.9	-	8.8	8.8	255.7
Sales in place	(16.0)	(1.3)	(17.3)	-	-	-	(17.3)
Production	(54.6)	(2.6)	(57.2)	(0.6)	-	(0.6)	(57.8)
Ending Reserves	**671.0**	**17.9**	**688.9**	**3.0**	**8.9**	**11.9**	**700.8**
NATURAL GAS LIQUIDS (MMBbls)							
Beginning Reserves	226.6	1.2	227.8	-	-	-	227.8
Revisions	47.3	0.6	47.9	-	-	-	47.9
Purchases in place	0.6	-	0.6	-	-	-	0.6
Extensions, discoveries and other additions	71.4	0.2	71.6	-	-	-	71.6
Sales in place	(7.3)	(0.1)	(7.4)	-	-	-	(7.4)
Production	(20.2)	(0.3)	(20.5)	-	-	-	(20.5)
Ending Reserves	**318.4**	**1.6**	**320.0**	**-**	**-**	**-**	**320.0**
NATURAL GAS (Bcf)							
Beginning Reserves	6,045.8	1,035.9	7,081.7	750.7	18.5	769.2	7,850.9
Revisions	(1,736.0)	(894.5)	(2,630.5)	(24.1)	1.6	(22.5)	(2,653.0)
Purchases in place	14.8	-	14.8	-	-	-	14.8
Extensions, discoveries and other additions	477.8	-	477.8	-	0.3	0.3	478.1
Sales in place	(386.2)	(8.5)	(394.7)	-	-	-	(394.7)
Production	(380.2)	(34.6)	(414.8)	(138.4)	(3.4)	(141.8)	(556.6)
Ending Reserves	**4,036.0**	**98.3**	**4,134.3**	**588.2**	**17.0**	**605.2**	**4,739.5**
OIL EQUIVALENTS (MMBoe)							
Beginning Reserves	1,729.5	192.5	1,922.0	128.6	3.2	131.8	2,053.8
Revisions	(237.9)	(151.0)	(388.9)	(3.9)	0.2	(3.7)	(392.6)
Purchases in place	4.1	-	4.1	-	-	-	4.1
Extensions, discoveries and other additions	392.2	5.8	398.0	-	8.9	8.9	406.9
Sales in place	(87.6)	(2.8)	(90.4)	-	-	-	(90.4)
Production	(138.2)	(8.7)	(146.9)	(23.6)	(0.6)	(24.2)	(171.1)
Ending Reserves	**1,662.1**	**35.8**	**1,697.9**	**101.1**	**11.7**	**112.8**	**1,810.7**
Net Proved Developed Reserves (MMBoe)							
At December 31, 2011	**877.3**	**58.5**	**935.8**	**103.7**	**3.2**	**106.9**	**1,042.7**
At December 31, 2012	**840.6**	**24.3**	**864.9**	**81.8**	**3.1**	**84.9**	**949.8**

2012 EXPLORATION AND DEVELOPMENT EXPENDITURES ($ Millions)

	United States	Canada	North America	Trinidad	Other Int'l	Total Int'l	Total
Acquisition Cost of Unproved Properties	$ 471.3	$ 33.6	$ 504.9	$ 1.0	$ (0.6)	$ 0.4	$ 505.3
Exploration Costs	333.6	38.5	372.1	19.6	53.9	73.5	445.6
Development Costs	5,576.9	245.7	5,822.6	31.1	135.9	167.0	5,989.6
Total Drilling	**6,381.8**	**317.8**	**6,699.6**	**51.7**	**189.2**	**240.9**	**6,940.5**
Acquisition Cost of Proved Properties	0.7	-	0.7	-	-	-	0.7
Total Exploration & Development Expenditures	**6,382.5**	**317.8**	**6,700.3**	**51.7**	**189.2**	**240.9**	**6,941.2**
Gathering, Processing and Other	633.4	50.2	683.6	0.2	1.8	2.0	685.6
Asset Retirement Costs	80.5	33.3	113.8	1.5	11.7	13.2	127.0
Total Expenditures	**7,096.4**	**401.3**	**7,497.7**	**53.4**	**202.7**	**256.1**	**7,753.8**
Proceeds from Sales in Place	(1,182.3)	(127.5)	(1,309.8)	-	-	-	(1,309.8)
Net Expenditures	**$ 5,914.1**	**$ 273.8**	**$ 6,187.9**	**$ 53.4**	**$ 202.7**	**$ 256.1**	**$ 6,444.0**
RESERVE REPLACEMENT COSTS ($ / Boe) *							
Total Drilling, Before Revisions	**$ 16.22**	**$ 54.79**	**$ 16.78**	**$ -**	**$ 21.26**	**$ 27.07**	**$ 17.01**
All-in Total, Net of Revisions	**$ 40.17**	**$ (2.19)**	**$ 506.06**	**$ (13.26)**	**$ 20.79**	**$ 46.33**	**$ 376.14**
All-in Total, Excluding Revisions Due to Price	**$ 11.82**	**$ 62.31**	**$ 12.29**	**$ (15.67)**	**$ 20.79**	**$ 41.53**	**$ 12.60**
RESERVE REPLACEMENT *							
Drilling Only	**284%**	**67%**	**271%**	**0%**	**1,483%**	**37%**	**238%**
All-in Total, Net of Revisions & Dispositions	**51%**	**-1,701%**	**-53%**	**-17%**	**1,517%**	**21%**	**-42%**
All-in Total, Excluding Revisions Due to Price	**326%**	**26%**	**308%**	**-14%**	**1,517%**	**24%**	**268%**
All-in Total, Liquids	**458%**	**90%**	**444%**	**17%**	**0%**	**1,483%**	**452%**

**** See attached reconciliation schedule for calculation methodology***

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF TOTAL EXPLORATION AND DEVELOPMENT EXPENDITURES
FOR DRILLING ONLY (NON-GAAP) AND TOTAL EXPLORATION AND DEVELOPMENT EXPENDITURES (NON-GAAP)
AS USED IN THE CALCULATION OF RESERVE REPLACEMENT COSTS ($ / BOE)
TO TOTAL COSTS INCURRED IN EXPLORATION AND DEVELOPMENT ACTIVITIES (GAAP)
(Unaudited; in millions, except ratio information)

The following chart reconciles Total Costs Incurred in Exploration and Development Activities (GAAP) to Total Exploration and Development Expenditures for Drilling Only (Non-GAAP) and Total Exploration and Development Expenditures (Non-GAAP), as used in the calculation of Reserve Replacement Costs per Boe. There are numerous ways that industry participants present Reserve Replacement Costs, including “Drilling Only” and “All-In”, which reflect total exploration and development expenditures divided by total net proved reserve additions from extensions and discoveries only, or from all sources. Combined with Reserve Replacement, these statistics provide management and investors with an indication of the results of the current year capital investment program. Reserve Replacement Cost statistics are widely recognized and reported by industry participants and are used by EOG management and other third parties for comparative purposes within the industry. Please note that the actual cost of adding reserves will vary from the reported statistics due to timing differences in reserve bookings and capital expenditures. Accordingly, some analysts use three or five year averages of reported statistics, while others prefer to estimate future costs. EOG has not included future capital costs to develop proved undeveloped reserves in exploration and development expenditures. The following chart also reconciles Total Expenditures (GAAP) to Total Cash Expenditures (Non-GAAP) in respect of EOG's 2012 capital expenditure program.

	United States	Canada	North America	Trinidad	Other Int'l	Total Int'l	Total
Total Costs Incurred in Exploration and Development Activities (GAAP)	$ 6,463.0	$ 351.1	$ 6,814.1	$ 53.2	$ 200.9	$ 254.1	$ 7,068.2
Less: Asset Retirement Costs	(80.5)	(33.3)	(113.8)	(1.5)	(11.7)	(13.2)	(127.0)
Non-Cash Acquisition Costs of Unproved Properties	(20.3)	-	(20.3)	-	-	-	(20.3)
Acquisition Cost of Proved Properties	(0.7)	-	(0.7)	-	-	-	(0.7)
Total Exploration & Development Expenditures for Drilling Only (Non-GAAP) (a)	**$ 6,361.5**	**$ 317.8**	**$ 6,679.3**	**$ 51.7**	**$ 189.2**	**$ 240.9**	**$ 6,920.2**
Total Costs Incurred in Exploration and Development Activities (GAAP)	$ 6,463.0	$ 351.1	$ 6,814.1	$ 53.2	$ 200.9	$ 254.1	$ 7,068.2
Less: Asset Retirement Costs	(80.5)	(33.3)	(113.8)	(1.5)	(11.7)	(13.2)	(127.0)
Non-Cash Acquisition Costs of Unproved Properties	(20.3)	-	(20.3)	-	-	-	(20.3)
Total Exploration & Development Expenditures (Non-GAAP) (b)	**$ 6,362.2**	**$ 317.8**	**$ 6,680.0**	**$ 51.7**	**$ 189.2**	**$ 240.9**	**$ 6,920.9**
Total Expenditures (GAAP)	$ 7,096.4	$ 401.3	$ 7,497.7	$ 53.4	$ 202.7	$ 256.1	$ 7,753.8
Less: Asset Retirement Costs	(80.5)	(33.3)	(113.8)	(1.5)	(11.7)	(13.2)	(127.0)
Non-Cash Gathering, Processing & Other Costs (Capital Lease)	(65.8)	-	(65.8)	-	-	-	(65.8)
Non-Cash Acquisition Costs of Unproved Properties	(20.3)	-	(20.3)	-	-	-	(20.3)
Total Cash Expenditures (Non-GAAP)	**$ 6,929.8**	**$ 368.0**	**$ 7,297.8**	**$ 51.9**	**$ 191.0**	**$ 242.9**	**$ 7,540.7**
Net Proved Reserve Additions From All Sources - Oil Equivalents (MMBoe)							
Revisions due to price (c)	(379.9)	(150.3)	(530.2)	(0.6)	-	(0.6)	(530.8)
Revisions other than price	142.0	(0.7)	141.3	(3.3)	0.2	(3.1)	138.2
Purchases in place	4.1	-	4.1	-	-	-	4.1
Extensions, discoveries and other additions (d)	392.2	5.8	398.0	-	8.9	8.9	406.9
Total Proved Reserve Additions (e)	**158.4**	**(145.2)**	**13.2**	**(3.9)**	**9.1**	**5.2**	**18.4**
Sales in place	(87.6)	(2.8)	(90.4)	-	-	-	(90.4)
Net Proved Reserve Additions From All Sources (f)	**70.8**	**(148.0)**	**(77.2)**	**(3.9)**	**9.1**	**5.2**	**(72.0)**
Production (g)	**138.2**	**8.7**	**146.9**	**23.6**	**0.6**	**24.2**	**171.1**
RESERVE REPLACEMENT COSTS ($ / BOE)							
Total Drilling, Before Revisions (a / d)	**$ 16.22**	**$ 54.79**	**$ 16.78**	**$ -**	**$ 21.26**	**$ 27.07**	**$ 17.01**
All-in Total, Net of Revisions (b / e)	**$ 40.17**	**$ (2.19)**	**$ 506.06**	**$ (13.26)**	**$ 20.79**	**$ 46.33**	**$ 376.14**
All-in Total, Excluding Revisions Due to Price (b / (e - c))	**$ 11.82**	**$ 62.31**	**$ 12.29**	**$ (15.67)**	**$ 20.79**	**$ 41.53**	**$ 12.60**
RESERVE REPLACEMENT							
Drilling Only (d / g)	**284%**	**67%**	**271%**	**0%**	**1,483%**	**37%**	**238%**
All-in Total, Net of Revisions & Dispositions (f / g)	**51%**	**-1,701%**	**-53%**	**-17%**	**1,517%**	**21%**	**-42%**
All-in Total, Excluding Revisions Due to Price ((f - c) / g)	**326%**	**26%**	**308%**	**-14%**	**1,517%**	**24%**	**268%**
Net Proved Reserve Additions From All Sources - Liquids (MMBbls)							
Revisions	51.4	(1.9)	49.5	0.1	-	0.1	49.6
Purchases in place	1.6	-	1.6	-	-	-	1.6
Extensions, discoveries and other additions (h)	312.6	5.9	318.5	-	8.8	8.8	327.3
Total Proved Reserve Additions	**365.6**	**4.0**	**369.6**	**0.1**	**8.8**	**8.9**	**378.5**
Sales in place	(23.3)	(1.4)	(24.7)	-	-	-	(24.7)
Net Proved Reserve Additions From All Sources (i)	**342.3**	**2.6**	**344.9**	**0.1**	**8.8**	**8.9**	**353.8**
Production (j)	**74.8**	**2.9**	**77.7**	**0.6**	**-**	**0.6**	**78.3**
RESERVE REPLACEMENT - LIQUIDS							
Drilling Only (h / j)	**418%**	**203%**	**410%**	**0%**	**0%**	**1,467%**	**418%**
All-in Total, Net of Revisions & Dispositions (i / j)	**458%**	**90%**	**444%**	**17%**	**0%**	**1,483%**	**452%**

EOG RESOURCES, INC.

FIRST QUARTER AND FULL YEAR 2013 FORECAST AND BENCHMARK COMMODITY PRICING

(a) First Quarter and Full Year 2013 Forecast

The forecast items for the first quarter and full year 2013 set forth below for EOG Resources, Inc. (EOG) are based on current available information and expectations as of the date of the accompanying press release. EOG undertakes no obligation, other than as required by applicable law, to update or revise this forecast, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise. This forecast, which should be read in conjunction with the accompanying press release and EOG's related Current Report on Form 8-K filing, replaces and supersedes any previously issued guidance or forecast.

(b) Benchmark Commodity Pricing

EOG bases United States, Canada and Trinidad crude oil and condensate price differentials upon the West Texas Intermediate crude oil price at Cushing, Oklahoma, using the simple average of the NYMEX settlement prices for each trading day within the applicable calendar month.

EOG bases United States and Canada natural gas price differentials upon the natural gas price at Henry Hub, Louisiana, using the simple average of the NYMEX settlement prices for the last three trading days of the applicable month.

	ESTIMATED RANGES (Unaudited)					
	1Q 2013			Full Year 2013		
Daily Production						
Crude Oil and Condensate Volumes (MBbld)						
United States	160.0	-	172.0	180.0	-	197.0
Canada	6.5	-	7.5	6.0	-	7.0
Trinidad	0.8	-	1.5	1.0	-	2.0
Other International	0.0	-	0.0	5.0	-	6.0
Total	167.3	-	181.0	192.0	-	212.0
Natural Gas Liquids Volumes (MBbld)						
United States	52.0	-	56.0	55.5	-	66.0
Canada	0.5	-	0.9	0.5	-	0.8
Total	52.5	-	56.9	56.0	-	66.8
Natural Gas Volumes (MMcfd)						
United States	900	-	930	865	-	905
Canada	70	-	85	64	-	80
Trinidad	335	-	365	350	-	375
Other International	8	-	11	8	-	10
Total	1,313	-	1,391	1,287	-	1,370
Crude Oil Equivalent Volumes (MBoed)						
United States	362.0	-	383.0	379.7	-	413.8
Canada	18.7	-	22.6	17.2	-	21.1
Trinidad	56.6	-	62.3	59.3	-	64.5
Other International	1.3	-	1.8	6.3	-	7.7
Total	438.6	-	469.7	462.5	-	507.1

ESTIMATED RANGES
(Unaudited)

	1Q 2013		Full Year 2013	
Operating Costs				
Unit Costs ($/Boe)				
Lease and Well	$ 6.27	- $ 6.57	$ 6.20	- $ 6.75
Transportation Costs	$ 4.55	- $ 4.80	$ 4.40	- $ 4.80
Depreciation, Depletion and Amortization	$ 20.75	- $ 21.55	$ 20.15	- $ 21.15
Expenses ($MM)				
Exploration, Dry Hole and Impairment	$ 127.0	- $ 142.0	$ 500.0	- $ 550.0
General and Administrative	$ 85.0	- $ 90.0	$ 365.0	- $ 385.0
Gathering and Processing	$ 28.0	- $ 32.0	$ 100.0	- $ 130.0
Capitalized Interest	$ 12.0	- $ 18.0	$ 50.0	- $ 62.0
Net Interest	$ 55.0	- $ 60.0	$ 205.0	- $ 225.0
Taxes Other Than Income (% of Wellhead Revenue)	6.2%	- 6.6%	5.6%	- 6.6%
Income Taxes				
Effective Rate	35%	- 45%	35%	- 45%
Current Taxes ($MM)	$ 50	- $ 65	$ 230	- $ 250
Capital Expenditures ($MM) - FY 2013 (Excluding Non-cash Items)				
Exploration and Development, Excluding Facilities			$ 5,900	- $ 6,000
Exploration and Development Facilities			$ 710	- $ 770
Gathering, Processing and Other			$ 435	- $ 465
Pricing - (Refer to Benchmark Commodity Pricing in text)				
Crude Oil and Condensate ($/Bbl)				
Differentials				
United States - above WTI	$ (8.50)	- $ (12.50)	$ (4.50)	- $ (9.50)
Canada - below WTI	$ 9.50	- $ 11.50	$ 7.85	- $ 10.85
Trinidad - below WTI	$ 1.05	- $ 3.05	$ 1.25	- $ 4.25
Natural Gas Liquids				
Realizations as % of WTI				
United States	35%	- 37%	34%	- 38%
Canada	50%	- 52%	50%	- 54%
Natural Gas ($/Mcf)				
Differentials				
United States - below NYMEX Henry Hub	$ 0.35	- $ 0.55	$ 0.30	- $ 0.60
Canada - below NYMEX Henry Hub	$ 0.11	- $ 0.21	$ 0.17	- $ 0.42
Realizations				
Trinidad	$ 3.12	- $ 3.62	$ 2.55	- $ 3.25
Other International	$ 4.80	- $ 5.30	$ 4.70	- $ 5.60

Definitions

$/Bbl	U.S. Dollars per barrel
$/Boe	U.S. Dollars per barrel of oil equivalent
$/Mcf	U.S. Dollars per thousand cubic feet
$MM	U.S. Dollars in millions
MBbld	Thousand barrels per day
Mboed	Thousand barrels of oil equivalent per day
MMcfd	Million cubic feet per day
NYMEX	New York Mercantile Exchange
WTI	West Texas Intermediate