EOG RESOURCES INC
Form 10-K
February 24, 2012

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

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

or

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

Commission file number: 1-9743

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

Delaware	47-0684736
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

Registrant's telephone number, including area code: 713-651-7000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes o No x

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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of June 30, 2011: $28,070,598,553.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. Class: Common Stock, par value $0.01 per share, 269,085,607 shares outstanding as of February 17, 2012.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2012 Annual Meeting of Stockholders to be filed within 120 days after December 31, 2011 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

(i)

PART I

ITEM 1. Business

General

EOG Resources, Inc., a Delaware corporation organized in 1985, together with its subsidiaries (collectively, EOG), explores for, develops, produces and markets crude oil and natural gas primarily in major producing basins in the United States of America (United States or U.S.), Canada, The Republic of Trinidad and Tobago (Trinidad), the United Kingdom (U.K.), The People's Republic of China (China), the Argentine Republic (Argentina) and, from time to time, select other international areas. EOG's principal producing areas are further described in "Exploration and Production" below. EOG's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports are made available, free of charge, through EOG's website, as soon as reasonably practicable after such reports have been filed with the United States Securities and Exchange Commission (SEC). EOG's website address is http://www.eogresources.com.

At December 31, 2011, EOG's total estimated net proved reserves were 2,054 million barrels of oil equivalent (MMBoe), of which 517 million barrels (MMBbl) were crude oil and condensate reserves, 228 MMBbl were natural gas liquids reserves and 7,851 billion cubic feet (Bcf), or 1,309 MMBoe, were natural gas reserves (see Supplemental Information to Consolidated Financial Statements). At such date, approximately 85% of EOG's net proved reserves, on a crude oil equivalent basis, were located in the United States, 9% in Canada and 6% in Trinidad. Crude oil equivalent volumes are determined using the ratio of 1.0 barrel of crude oil and condensate or natural gas liquids to 6.0 thousand cubic feet (Mcf) of natural gas.

As of December 31, 2011, EOG employed approximately 2,550 persons, including foreign national employees.

EOG's business strategy is to maximize the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis. EOG is focused on cost-effective utilization of advanced technology associated with three-dimensional seismic and microseismic data, the development of reservoir simulation models, the use of improved drill bits, mud motors and mud additives for horizontal drilling, formation evaluation, and horizontal completion methods. These advanced technologies are used, as appropriate, throughout EOG to reduce the risks associated with all aspects of oil and gas exploration, development and exploitation. EOG implements its strategy by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure that is consistent with prudent and safe operations is also an important goal in the implementation of EOG's strategy.

With respect to information on EOG's working interest in wells or acreage, "net" oil and gas wells or acreage are determined by multiplying "gross" oil and gas wells or acreage by EOG's working interest in the wells or acreage.

Business Segments

EOG's operations are all crude oil and natural gas exploration and production related. For financial information about our reportable segments (including financial information by segment geographic area), see Note 10 to Consolidated Financial Statements. For information regarding the risks associated with EOG's foreign operations, see Item 1A. Risk Factors.

1

Exploration and Production

United States and Canada Operations

EOG's operations are focused on most of the productive basins in the United States and Canada, with a current focus on liquids-rich plays.

At December 31, 2011, 39% of EOG's net proved reserves in the United States and Canada (on a crude oil equivalent basis) were crude oil and condensate and natural gas liquids and 61% were natural gas reserves. Substantial portions of these reserves are in long-lived fields with well-established production characteristics. EOG believes that opportunities exist to increase production through continued development in and around many of these fields and through the utilization of the applicable technologies described above. EOG also maintains an active exploration program designed to extend fields and add new trends and resource plays to its broad portfolio. The following is a summary of significant developments during 2011 and certain 2012 plans for EOG's United States and Canada operations.

United States. The liquids-rich Eagle Ford Shale has proven to be among EOG's most economically attractive resource plays to date. The Eagle Ford has well-defined crude oil, wet gas and dry gas trends. EOG's total acreage position in all three hydrocarbon trends totals 647,000 net acres. EOG has focused its drilling on its highly productive 572,000 net acreage position within the oil window where EOG has drilled a cumulative 356 net wells. EOG's strategy is to maintain its entire ownership interests and not to dilute its position by taking on a joint venture partner in this play. EOG is the largest oil producer in the Eagle Ford where its net production in 2011 was 30.2 thousand barrels per day (MBbld) of crude oil and condensate, 3.9 MBbld of natural gas liquids and 21 million cubic feet per day (MMcfd) of natural gas. This represents more than a six-fold, year-over-year increase in production. EOG drilled 269 net wells in 2011 and plans to drill and complete approximately 280 net wells in 2012.

In 2011, EOG increased activity in the liquids-rich Barnett Shale Combo play of the Fort Worth Basin where total production grew by approximately 105% above 2010 levels, including a 107% increase in liquids production. During the year, EOG completed 269 net Barnett Combo wells and increased its drilling potential in this liquids-rich play by expanding the core area from approximately 175,000 to approximately 200,000 net acres. EOG's total 2011 Barnett Shale average net daily production increased to approximately 37.7 MBbld of crude oil and condensate and natural gas liquids and 403 MMcfd of natural gas. For 2012, EOG will continue to focus on this play with plans to complete to sales an additional 200 net Barnett Shale Combo wells. In the natural gas portion of the Barnett Shale, EOG plans to complete to sales approximately 35 net wells. The rich natural gas from the majority of these wells will be processed to recover natural gas liquids. With a large acreage position of approximately 506,000 net acres in the Barnett Shale and a history of strong drilling results, EOG expects to continue to be an active driller in the Fort Worth Basin Barnett Shale for many years.

EOG maintained a strong and consistent development program throughout the Rocky Mountain area in 2011. EOG continued its development programs in the Williston, DJ and Uinta basins, drilling 79 net wells, 36 net wells and 33 net wells, respectively. EOG also resumed exploration and development activities in the Powder River Basin during 2011, drilling six net wells. Net average production for the entire Rocky Mountain area for 2011 was 46.6 MBbld of crude oil and condensate and natural gas liquids, an increase of 13% over the prior year. Natural gas production was down 17% from 2010 levels primarily due to divestitures and de-emphasized natural gas drilling. EOG holds approximately 1.6 million net acres in the Rocky Mountain area. For 2012, EOG intends to maintain a steady development program throughout the Rocky Mountain area where it plans to drill 123 net wells.

In 2011, EOG drilled and participated in 56 net wells in the Permian Basin to test the Leonard-Avalon Shale, Bone Spring and Wolfcamp formations. EOG is well positioned in these three established plays: the Leonard-Avalon Shale and Bone Spring plays in the Delaware Basin and the Wolfcamp Shale in the Midland Basin. Net production for the year 2011 averaged 10.5 MBbld of crude oil and condensate and natural gas liquids and 49 MMcfd of natural gas. After divestitures in 2011, EOG now controls approximately 480,000 net acres throughout the Permian Basin, with approximately 130,000 acres within the Wolfcamp Shale formation and 106,000 acres within the limits of the Bone Spring and Leonard-Avalon Shale formations. In 2012, EOG plans to continue the development, expansion and enhancement of the Wolfcamp, Leonard-Avalon and Bone Spring plays, by drilling 112 net wells, while continuing to look for new liquids-rich plays.

In 2011, EOG continued to expand its activities in the Mid-Continent area with continued growth and extension of its Western Anadarko Basin core area. For the year, EOG averaged net production of 7.1 MBbld of crude oil and condensate and natural gas liquids and 52 MMcfd of natural gas. Total crude oil and condensate and natural gas liquids volumes increased 22% in 2011 compared to 2010. In 2011, EOG continued its successful horizontal exploitation of the Cleveland sandstone, drilling 11 net wells with initial average gross production rates of approximately 350 barrels per day (Bbld) of crude oil and condensate and natural gas liquids per well. Since 2002, EOG has drilled over 230 net wells in this play and holds approximately 100,000 net acres throughout the trend. In the recently discovered Marmaton Sandstone play, where it holds approximately 80,000 net acres, EOG drilled a total of 18 net wells in 2011 with an initial average gross production rate of 550 Bbld of crude oil and condensate and natural gas liquids per well. In 2012, approximately 40 net wells are planned in order to further exploit these liquids-rich plays.

In the South Texas area, EOG drilled 47 net wells in 2011. Net production during 2011 averaged 6.4 MBbld of crude oil and condensate and natural gas liquids and 151 MMcfd of natural gas. EOG's activity was focused in Webb, Zapata, San Patricio, Nueces, Brooks and Kenedy counties. EOG will continue to focus on drilling liquids-rich wells in the Lobo and Roleta trends, the Frio and Vicksburg trends and the Nueces Wilcox trend. EOG holds approximately 364,500 net acres in South Texas. Approximately 43 net wells are planned for South Texas during 2012. EOG's Gulf of Mexico production of crude oil, condensate and natural gas liquids averaged approximately 75 Bbld for the year ended December 31, 2011. Thus, EOG's offshore operations in the Gulf of Mexico are immaterial in relation to EOG's overall operations and production; moreover, EOG does not have any plans for future offshore drilling in the Gulf of Mexico.

In the Upper Gulf Coast region, EOG drilled 47 net wells and net production averaged 227 MMcfd of natural gas and 1.0 MBbld of crude oil and condensate and natural gas liquids in 2011. The Haynesville and Bossier Shale plays located near the Texas-Louisiana border continue to be core natural gas assets for EOG. The drilling program has increased from 13 net wells in 2009 to 40 net wells in 2011. EOG expanded the Texas "sweet spot" in 2011 with excellent well results in southern Nacogdoches and Angelina counties. EOG now controls 175,000 net acres in this play, and most of this acreage is within a well-defined productive sweet spot. EOG holds a total of approximately 384,000 net acres in the Upper Gulf Coast region. Due to low natural gas prices, EOG plans to reduce activity and drill approximately 25 net wells in the Upper Gulf Coast region in 2012, including 15 net wells in the Haynesville.

During 2011, EOG continued the development of its Pennsylvania Marcellus Shale asset and drilled a total of 27 net wells. Nine net wells were drilled in Bradford County in northeastern Pennsylvania, and seven net wells were completed. The remaining 18 net wells were drilled in north central Pennsylvania, as part of EOG's joint venture with Seneca Resources Corporation where EOG is operator and holds a 50% working interest. EOG's net natural gas production averaged 33 MMcfd in 2011, up from 12 MMcfd in 2010. EOG currently holds in excess of 200,000 net acres in the Pennsylvania Marcellus Shale and plans to drill an estimated 35 net wells during 2012.

At December 31, 2011, EOG held approximately 3.6 million net undeveloped acres in the United States.

During 2011, EOG continued the expansion of its gathering and processing activities in the Barnett Shale of North Texas and the Bakken and Three Forks plays of North Dakota. EOG also installed field gathering and conditioning facilities in the Eagle Ford play of South Texas. EOG-owned natural gas processing capacity at December 31, 2011 in the Barnett Shale and Eagle Ford was 120 MMcfd and 135 MMcfd, respectively.

During June 2011, EOG sold its Stanley, North Dakota, condensate recovery unit and 76-mile, 12-inch diameter "dense phase" natural gas pipeline. In connection with the sale, EOG entered into an agreement with the buyer to reserve capacity in both the condensate recovery unit and the pipeline. The pipeline connects with the Alliance Pipeline which transports natural gas to the Chicago, Illinois, area.

Additionally, in support of its operations in the Williston Basin, EOG increased utilization of its crude oil loading facility near Stanley, North Dakota, to transport its oil production and oil purchased from third-party producers. Using this facility during 2011, EOG loaded 200 unit trains (each unit train typically consists of 100 cars and has a total aggregate capacity of approximately 68,000 barrels of crude oil) with crude oil for transport to Stroud, Oklahoma, and certain destinations on the U.S. Gulf Coast. In Stroud, Oklahoma, EOG owns a crude oil off-loading facility and a pipeline to transport the crude oil to the Cushing, Oklahoma, trading hub. Together, these facilities have the capacity to load/unload approximately 70 MBbld of crude oil.

In the South Texas Eagle Ford, EOG established a crude oil loading facility in Harwood, Texas, that became operational in April 2011. At this facility, crude oil is loaded onto unit trains of approximately 70 cars each, with capacity of approximately 46,000 barrels per train, and is shipped to destinations on the U.S. Gulf Coast. During 2011, a total of 45 shipments were made from the Harwood facility.

In order to access more diverse markets for its crude-by-rail shipments, during 2011 EOG began construction of a crude oil unloading facility in St. James, Louisiana, where sales are based upon the Light Louisiana Sweet price. This facility, which is scheduled to be operational in the second quarter of 2012, will have a capacity of approximately 100 MBbld, and be able to accommodate multiple trains at a single time.

EOG believes that its crude-by-rail facilities uniquely position it to direct its crude oil shipments via rail car from North Dakota and Texas to the most favorable markets.

Since 2008, EOG has been operating its own sand mine and sand processing plant located in Hood County, Texas, helping to fulfill EOG's sand needs in the Barnett Shale Combo play.

During 2011, EOG increased its sand mining and processing operations to supply sand for its well completion operations. EOG purchased a second processing plant in Hood County, Texas, in 2011, and began regular shipments of EOG-owned unprocessed sand from Wisconsin. After final processing at the Hood County facility, the sand is being utilized in key EOG plays.

During December 2011, EOG completed and placed in operation its new state-of-the-art Chippewa Falls, Wisconsin, sand plant to process sand from a nearby EOG-owned sand mine. The first unit train of processed sand was dispatched from Chippewa Falls at the beginning of January 2012. The majority of the initial trains are destined for a new EOG sand facility in Refugio, Texas. One to two sand unit trains of approximately 100 cars each are expected to arrive at Refugio every week as operations in Chippewa Falls ramp up. From there, the sand will be shipped primarily to the South Texas Eagle Ford play.

Canada. EOG conducts operations through its wholly-owned subsidiary, EOG Resources Canada Inc. (EOGRC), from its offices in Calgary, Alberta. During 2011, EOGRC continued its focus on horizontal crude oil growth, mainly through its drilling activity in Waskada, Manitoba. Other drilling activity was directed to acreage retention in its bigger target horizontal natural gas play in the Horn River Basin of British Columbia. During 2011, EOGRC drilled or participated in 101 net wells, all of which were horizontal wells. Correspondingly, net crude oil and condensate and natural gas liquids production increased by 16% to 8.8 MBbld. Net natural gas production decreased 34% to 132 MMcfd, reflecting a de-emphasis on gas drilling and EOGRC's sale of several shallow gas properties in late 2010. The focus on crude oil production growth will continue in 2012 with 133 net wells planned in a combination of plays from the continued development in Manitoba and new targets in Alberta. EOG plans to drill seven net wells in the Horn River Basin for acreage retention in 2012.

At December 31, 2011, EOGRC held approximately 749,000 net undeveloped acres in Canada.

In March 2011, EOGRC purchased an additional 24.5% interest in the proposed Pacific Trail Pipelines (PTP) for $25.2 million. The PTP is intended to link western Canada's natural gas producing regions to the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia (Kitimat LNG Terminal). A portion of the purchase price ($15.3 million) was paid at closing with the remaining amount to be paid contingent on the decision to proceed with the construction of the Kitimat LNG Terminal. Additionally, in March 2011, EOGRC and an affiliate of Apache Corporation (Apache), through a series of transactions, sold a portion of their interests in the Kitimat LNG Terminal and PTP to an affiliate of Encana Corporation (Encana). Subsequent to these transactions, ownership interests in both the Kitimat LNG Terminal and

PTP are: Apache (operator) 40%, EOGRC 30% and Encana 30%. All future costs of the project will be paid by each party in proportion to its respective ownership percentage. In the first quarter of 2011, EOGRC and Apache awarded a front-end engineering and design contract to a global engineering company with the final report expected in the second half 2012. In October 2011, the Canadian National Energy Board granted a 20-year export license to ship LNG from the Kitimat LNG Terminal to international markets.

Operations Outside the United States and Canada

EOG has operations offshore Trinidad, the U.K. North Sea and East Irish Sea, the China Sichuan Basin and the Neuquén Basin of Argentina, and is evaluating additional exploration, development and exploitation opportunities in these and other select international areas.

Trinidad. EOG, through several of its subsidiaries, including EOG Resources Trinidad Limited,

- holds an 80% working interest in the South East Coast Consortium (SECC) Block offshore Trinidad, except in the Deep Ibis area in which EOG's working interest decreased as a result of a third-party farm-out agreement;
- holds an 80% working interest in the exploration and production license covering the Pelican Field and its related facilities;
- holds a 50% working interest in the exploration and production license covering the EMZ Area offshore Trinidad as a result of a third party farm-out agreement which was executed in the fourth quarter of 2011;
- holds a 100% working interest in a production sharing contract with the Government of Trinidad and Tobago for each of the Modified U(a) Block, Modified U(b) Block and Block 4(a);
- owns a 12% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Caribbean Nitrogen Company Limited (CNCL); and
- owns a 10% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Nitrogen (2000) Unlimited (N2000).

Several fields in the SECC Block, Modified U(a) Block and Modified U(b) Block, as well as the Pelican Field, have been developed and are producing natural gas and crude oil and condensate. In Block 4(a), EOG drilled and completed six development wells in the Toucan Field and one in the Sercan Field in 2011. Production from both the Toucan Field and EMZ Area began in February 2012 to supply natural gas under a contract with the National Gas Company of Trinidad and Tobago (NGC). EOG sourced the natural gas for this contract from its existing fields until the Toucan Field began producing.

Natural gas from EOG's Trinidad operations currently is sold to NGC or its subsidiary. Certain agreements with NGC require EOG's Trinidad operations to deliver in 2012 approximately 520 MMcfd (370 MMcfd, net) of natural gas, under current economic conditions. EOG intends to fulfill these natural gas delivery obligations by using production from existing proved reserves. Crude oil and condensate from EOG's Trinidad operations currently is sold to the Petroleum Company of Trinidad and Tobago.

In 2011, EOG's average net production from Trinidad was 344 MMcfd of natural gas and 3.4 MBbld of crude oil and condensate.

At December 31, 2011, EOG held approximately 39,000 net undeveloped acres in Trinidad.

United Kingdom. EOG's subsidiary, EOG Resources United Kingdom Limited (EOGUK), owns a 25% non-operating working interest in a portion of Block 49/16a, located in the Southern Gas Basin of the North Sea. During 2011, production continued from the Valkyrie field in this block.

EOGUK also owns a 30% non-operating working interest in a portion of Blocks 53/1 and 53/2. These blocks are also located in the Southern Gas Basin of the North Sea.

In 2006, EOGUK participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. EOG has a 25% non-operating interest in this block. A successful Columbus prospect appraisal well was drilled during the third quarter of 2007. The field operator submitted a revised field development plan to the U.K.

Department of Energy and Climate Change (DECC) during the second quarter of 2011 and anticipates receiving approval of this plan in the first half of 2012. The operator and partners are continuing to negotiate processing and transportation terms with export infrastructure owners.

In 2009, EOGUK drilled a successful exploratory well in its East Irish Sea Blocks 110/7b and 110/12a. Well 110/12-6, in which EOGUK has a 100% working interest, was an oil discovery and was designated the Conwy field. In 2010, EOGUK added an adjoining field in its East Irish Sea block, designated Corfe, to its overall development plans. During 2011, offshore facilities fabrication began, line pipe was fabricated and all principal facilities and drilling contracts were signed. Field development plans for the Conwy and Corfe fields were submitted to the DECC during the first quarter of 2011. Regulatory approval of both plans is expected during the first quarter of 2012. Installation of facilities, pipelines and drilling of development wells are planned for 2012, with initial production expected during the first quarter of 2013. The licenses for the East Irish Sea blocks were awarded to EOGUK in 2007.

In 2011, production averaged 3 MMcfd of natural gas, net, in the United Kingdom.

At December 31, 2011, EOG held approximately 95,000 net undeveloped acres in the United Kingdom.

China. In July 2008, EOG acquired rights from ConocoPhillips in a Petroleum Contract covering the Chuanzhong Block exploration area in the Sichuan Basin, Sichuan Province, China. In October 2008, EOG obtained the rights to shallower zones on the acreage acquired. During the first quarter of 2011, EOG completed one horizontal well.

In 2011, production averaged 10 MMcfd of natural gas, net, in China.

At December 31, 2011, EOG held approximately 131,000 net acres in China.

Argentina. During 2011, EOG signed two exploration contracts and one farm-in agreement covering approximately 100,000 net acres in the Neuquén Basin in Neuquén Province, Argentina. During the third quarter of 2011, EOG performed exploration activity on a portion of this acreage in preparation for drilling a well targeting the Vaca Muerta oil shale in the Aguada del Chivato Block. EOG began drilling this well in January 2012. In the first quarter of 2012, EOG plans to participate in drilling a second well in the Bajo del Toro Block targeting the Vaca Muerta oil shale.

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

Marketing

Wellhead Marketing. Substantially all of EOG's wellhead crude oil and condensate and natural gas liquids are sold under various terms and arrangements based on prevailing market prices.

In 2011, EOG's United States and Canada wellhead natural gas production was sold on the spot market and under long-term natural gas contracts based on prevailing market prices. In many instances, the long-term contract prices closely approximated the prices received for natural gas sold on the spot market. In 2012, the pricing mechanism for such production is expected to remain the same.

In 2011, a large majority of the wellhead natural gas volumes from Trinidad were sold under contracts with prices which were either wholly or partially dependent on Caribbean ammonia index prices and/or methanol prices. The remaining volumes were sold under a contract at prices partially dependent on United States Henry Hub market prices. The pricing mechanisms for these contracts in Trinidad are expected to remain the same in 2012.

In 2011, all wellhead natural gas volumes from the United Kingdom were sold on the spot market. The 2012 marketing strategy for the wellhead natural gas volumes from the United Kingdom is expected to remain the same.

In 2011, all of the wellhead natural gas volumes from China were sold under a contract with prices based on the purchaser's pipeline sales prices to various local market segments. The pricing mechanism for the contract in China is expected to remain the same in 2012.

In certain instances, EOG purchases and sells third-party crude oil and natural gas in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities.

During 2011, a single purchaser accounted for 10.1% of EOG's total wellhead crude oil and condensate, natural gas liquids and natural gas revenues and gathering, processing and marketing revenues. EOG does not believe that the loss of any single purchaser would have a material adverse effect on its financial condition or results of operations.

Wellhead Volumes and Prices

The following table sets forth certain information regarding EOG's wellhead volumes of, and average prices for, crude oil and condensate, natural gas liquids and natural gas. The table also presents crude oil equivalent volumes which are determined using the ratio of 1.0 Bbl of crude oil and condensate or natural gas liquids to 6.0 Mcf of natural gas for each of the years ended December 31, 2011, 2010 and 2009.

Year Ended December 31	2011	2010	2009
Crude Oil and Condensate Volumes (MBbld) (1)			
United States:			
Eagle Ford	30.2	4.1	-
Barnett	15.2	6.8	2.8
Other	56.6	52.3	45.1
United States	102.0	63.2	47.9
Canada	7.9	6.7	4.1
Trinidad	3.4	4.7	3.1
Other International (2)	0.1	0.1	0.1
Total	113.4	74.7	55.2
Natural Gas Liquids Volumes (MBbld) (1)			
United States:			
Eagle Ford	3.9	0.2	-
Barnett	22.6	16.3	10.3
Other	15.0	13.0	12.2
United States	41.5	29.5	22.5
Canada	0.9	0.9	1.1
Total	42.4	30.4	23.6
Natural Gas Volumes (MMcfd) (1)			
United States:			
Eagle Ford	21	4	-
Barnett	403	404	400
Other	689	725	734
United States	1,113	1,133	1,134
Canada	132	200	224
Trinidad	344	341	273
Other International (2)	13	14	14
Total	1,602	1,688	1,645
Crude Oil Equivalent Volumes (MBoed) (3)			
United States:			
Eagle Ford	37.7	5.0	-
Barnett	105.0	90.5	79.8
Other	186.4	186.0	179.6
United States	329.1	281.5	259.4

Canada	30.7	40.9	42.6
Trinidad	60.7	61.5	48.5
Other International (2)	2.2	2.5	2.4
Total	422.7	386.4	352.9
Total MMBoe (3)	154.3	141.1	128.8

Year Ended December 31	2011	2010	2009
Average Crude Oil and Condensate Prices ($/Bbl) (4)			
United States	$92.92	$74.88	$54.42
Canada	91.92	72.66	57.72
Trinidad	90.62	68.80	50.85
Other International (2)	100.11	73.11	53.07
Composite	92.79	74.29	54.46
Average Natural Gas Liquids Prices ($/Bbl) (4)			
United States	$50.37	$41.68	$30.03
Canada	52.69	43.40	30.49
Composite	50.41	41.73	30.05
Average Natural Gas Prices ($/Mcf) (4)			
United States	$3.92	$4.30	$3.72
Canada	3.71	3.91	3.85
Trinidad	3.53	2.65	1.73
Other International (2)	5.62	4.90	4.34
Composite	3.83	3.93	3.42

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

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

(3) 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. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

(4) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 11 to Consolidated Financial Statements).

Competition

EOG competes with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and the equipment, materials, services and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market crude oil and natural gas. Moreover, many of EOG's competitors have financial and other resources substantially greater than those EOG possesses and have established strategic long-term positions and strong governmental relationships in countries in which EOG may seek new or expanded entry. As a consequence, EOG may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights. In addition, many of EOG's larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. EOG also faces competition, to a lesser extent, from competing energy sources, such as alternative energy sources.

Regulation

United States Regulation of Crude Oil and Natural Gas Production. Crude oil and natural gas production operations are subject to various types of regulation, including regulation in the United States by federal and state agencies.

United States legislation affecting the oil and gas industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue and have issued rules and regulations which, among other things, require permits for the drilling of wells, regulate the spacing of wells, prevent the waste of natural gas and liquid hydrocarbon resources through proration and restrictions on flaring, require drilling bonds, regulate environmental and safety matters and regulate the calculation and disbursement of royalty payments, production taxes and ad valorem taxes.

A substantial portion of EOG's oil and gas leases in Utah, New Mexico, Wyoming and the Gulf of Mexico, as well as some in other areas, are granted by the federal government and administered by the Bureau of Land Management (BLM), the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), all federal agencies. Operations conducted by EOG on federal oil and gas leases must comply with numerous additional statutory and regulatory restrictions. Certain operations must be conducted pursuant to appropriate permits issued by the BLM and the BSEE.

BLM and BOEM leases contain relatively standardized terms requiring compliance with detailed regulations and, in the case of offshore leases, orders pursuant to the Outer Continental Shelf Lands Act (which are subject to change by the BOEM or BSEE). Such offshore operations are subject to numerous regulatory requirements, including the need for prior BOEM and/or BSEE approval for exploration, development and production plans; stringent engineering and construction specifications applicable to offshore production facilities; regulations restricting the flaring or venting of production; regulations governing the plugging and abandonment of offshore wells; and the requirements for removal of all production facilities. Under certain circumstances, the BOEM or BSEE may require operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect EOG's interests.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. These statutes are administered by the Federal Energy Regulatory Commission (FERC). Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by EOG of its own production. All other sales of natural gas by EOG, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of EOG's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. EOG's jurisdictional sales, however, are subject to the future possibility of greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of crude oil and condensate and natural gas liquids by EOG are made at unregulated market prices.

EOG owns certain natural gas pipelines that it believes meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction under the NGA. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. EOG's gathering operations could be materially and adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

EOG's gathering operations also may be, or become, subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of such facilities. Additional rules and legislation pertaining to these matters are considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, such legislation might have on its operations and financial condition, the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Proposals and proceedings that might affect the oil and gas industry are considered from time to time by Congress, the state legislatures, the FERC and federal and state regulatory commissions and courts. EOG cannot predict when or whether any such proposals or proceedings may become effective. It should also be noted that the oil and gas industry historically has been very heavily regulated; therefore, there is no assurance that the approach currently being followed by such legislative bodies and regulatory agencies and courts will continue indefinitely.

Canadian Regulation of Crude Oil and Natural Gas Production. The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. These regulatory authorities may impose regulations on or otherwise intervene in the oil and gas industry with respect to taxes and factors affecting prices, transportation rates, the exportation of the commodity and, possibly, expropriation or cancellation of contract rights. Such regulations may be changed from time to time in response to economic, political or other factors. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for these commodities or increase EOG's costs and, therefore, may have a material adverse impact on EOG's operations and financial condition.

It is not expected that any of these controls or regulations will affect EOG's operations in a manner materially different than they would affect other oil and gas companies of similar size; however, EOG is unable to predict what additional legislation or amendments may be enacted or how such additional legislation or amendments may affect EOG's operations and financial condition.

In addition, each province has regulations that govern land tenure, royalties, production rates and other matters. The royalty system in Canada is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from freehold lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Royalties payable on lands that the government has an interest in are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type and quality of the petroleum product produced. From time to time, the federal and provincial governments of Canada have also established incentive programs such as royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and gas exploration or enhanced recovery projects. These incentives generally have the effect of increasing EOG's revenues, earnings and cash flow.

Environmental Regulation - United States. Various federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect EOG's operations and costs as a result of their effect on crude oil and natural gas exploration, development and production operations. These laws and regulations could cause EOG to incur remediation or other corrective action costs in connection with a release of regulated substances, including crude oil, into the environment. In addition, EOG has acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under EOG's control and, under environmental laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. EOG also could incur costs related to the clean-up of third-party sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such third-party sites. In addition, EOG could be responsible under environmental laws and regulations for oil and gas properties in which EOG owns an interest but is not the operator. Moreover, EOG is subject to the U.S. Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions and may in the future, as discussed further below, be subject to federal, state and local laws and regulations regarding hydraulic fracturing.

Compliance with such laws and regulations increases EOG's overall cost of business, but has not had, to date, a material adverse effect on EOG's operations, financial condition or results of operations. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations but, inasmuch as such laws and regulations are frequently changed, EOG is unable to predict the ultimate cost of compliance or the effect on EOG's operations, financial condition and results of operations.

Climate Change. Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, recent U.S. EPA rulemaking may result in the regulation of GHGs as pollutants under the federal Clean Air Act. EOG supports efforts to understand and address the contribution of human activities to global climate change through the application of sound scientific research and analysis. Moreover, EOG believes that its strategy to reduce GHG emissions throughout its operations is in the best interest of the environment and is a generally good business practice.

EOG has developed a system that is utilized in calculating GHG emissions from its operating facilities. This emissions management system calculates emissions based on recognized regulatory methodologies, where applicable, and on commonly accepted engineering practices. EOG is now reporting GHG emissions for facilities covered under the U.S. EPA's Mandatory Reporting of Greenhouse Gases Rule published on October 30, 2009. EOG is unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Hydraulic Fracturing. Most onshore crude oil and natural gas wells drilled by EOG are completed and stimulated through the use of hydraulic fracturing. There have been various proposals to regulate hydraulic fracturing at the federal level. Hydraulic fracturing technology, which has been used by the oil and gas industry for more than 60 years and is constantly being enhanced, enables EOG to produce crude oil and natural gas from formations that would otherwise not be recovered. Specifically, hydraulic fracturing is a process in which pressurized fluid is pumped into underground formations to create tiny fractures or spaces that allow crude oil and natural gas to flow from the reservoir into the well so that it can be brought to the surface. Hydraulic fracturing generally takes place thousands of feet underground, a considerable distance below any drinking water aquifers, and there are impermeable layers of rock between the area fractured and the water aquifers. The makeup of the fluid used in the hydraulic fracturing process is typically more than 99% water and sand, and less than 1% of highly diluted chemical additives; lists of the chemical additives most typically used in fracturing fluids are available to the public via internet websites and in other publications sponsored by industry trade associations and through state agencies in those states that require the reporting of the components of fracturing fluids. While the majority of the sand remains underground to hold open the fractures, a significant percentage of the water and chemical additives flow back and are then either reused or safely disposed of at sites that are approved and permitted by the appropriate regulatory authorities. EOG regularly conducts audits of these disposal facilities to monitor compliance with all applicable regulations.

Currently, the regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements (such as the reporting and public disclosure of the chemical additives used in the fracturing process) and in additional operating restrictions. In addition to these federal proposals, some states and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; disclosure of the chemical additives used in hydraulic fracturing operations; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Such federal, state and local permitting and disclosure requirements and operating restrictions and conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing.

EOG is unable to predict the timing, scope and effect of any currently proposed or future laws or regulations regarding hydraulic fracturing, but the direct and indirect costs of such laws and regulations (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Environmental Regulation - Canada. All phases of the oil and gas industry in Canada are subject to environmental regulation pursuant to a variety of Canadian federal, provincial and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances into the environment. These laws and regulations also require that facility sites and other properties associated with EOG's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, new projects or changes to existing projects may require the submission and approval of environmental assessments or permit applications.

Spills and releases from EOG's properties may have resulted, or may result, in soil and groundwater contamination in certain locations. Any contamination found on, under or originating from the properties may be subject to remediation requirements under Canadian laws. In addition, EOG has acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under EOG's control. Under Canadian laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. In addition, EOG could be held responsible for oil and gas properties in which EOG owns an interest but is not the operator.

These laws and regulations are subject to frequent change, and the clear trend is to place increasingly stringent limitations on activities that may affect the environment. Compliance with such laws and regulations increases EOG's overall cost of business, but has not had, to date, a material adverse effect on EOG's operations, financial condition or results of operations. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations, but, inasmuch as such laws and regulations are frequently changed, EOG is unable to predict the ultimate cost of compliance or the effect on EOG's operations, financial condition and results of operations.

Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. The Canadian federal government has indicated an intention to work with the United States to regulate industrial emissions of GHG and air pollutants from a broad range of industrial sectors, with a stated goal to reduce Canada's total GHG emissions by 17% from 2005 levels by 2020. In addition, regulation of GHG emissions in Canada takes place at the provincial and municipal level. For example, the Alberta Government regulates GHG emissions under the Climate Change and Emissions Management Act, the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements, and the Specified Gas Emitters Regulation, which imposes GHG emissions limits. British Columbia regulates GHG emissions under the Greenhouse Gas Reduction Targets Act, the Greenhouse Gas Reduction (Cap and Trade) Act, which imposes hard caps on GHG emissions, and the Reporting Regulation, which requires mandatory reporting of GHG emissions. In addition, the Government of Manitoba is currently considering the creation of a cap-and-trade system to reduce GHG emissions in Manitoba. Canada was an original signatory to the United Nations Framework Convention on Climate Change (also known as the Kyoto Protocol), but Canada recently announced its withdrawal from the Kyoto Protocol, effective December 2012.

Other International Regulation. EOG's exploration and production operations outside the United States and Canada are subject to various types of regulations imposed by the respective governments of the countries in which EOG's operations are conducted, and may affect EOG's operations and costs of compliance within that country. EOG currently has operations in Trinidad, the United Kingdom, China and Argentina.

EOG is unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, including those regarding climate change and hydraulic fracturing, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations. EOG will continue to review the risks to its business and operations associated with all environmental matters, including climate change and hydraulic fracturing. In addition, EOG will continue to monitor and assess any new policies, legislation, regulations and treaties in the areas where it operates to determine the impact on its operations and take appropriate actions, where necessary.

Other Matters

Energy Prices. EOG is a crude oil and natural gas producer and is impacted by changes in prices for crude oil and condensate, natural gas liquids and natural gas. Crude oil and condensate and natural gas liquids production comprised a larger portion of EOG's production mix in 2011 than in prior years and is expected to comprise an even larger portion in 2012. Average crude oil and condensate prices received by EOG for production in the United States and Canada increased by 24% in 2011, increased by 37% in 2010 and decreased by 38% in 2009, each as compared to the immediately preceding year. The average New York Mercantile Exchange (NYMEX) crude oil strip price for 2012 has increased approximately 7% subsequent to December 31, 2011. Average United States and Canada wellhead natural gas prices have fluctuated, at times rather dramatically, during the last three years. These fluctuations resulted in an 8% decrease in the average wellhead natural gas price received by EOG for production in the United States and Canada in 2011, an increase of 13% in 2010 and a decrease of 54% in 2009, each as compared to the immediately preceding year. The average NYMEX natural gas strip price for 2012 has decreased by approximately 6% since December 31, 2011. Due to the many uncertainties associated with the world political environment, the availability of other energy supplies, the relative competitive relationships of the various energy sources in the view of consumers and other factors, EOG is unable to predict what changes may occur in crude oil and condensate, natural gas liquids and natural gas prices in the future. For additional discussion regarding changes in crude oil and natural gas prices and the risks that such changes may present to EOG, see ITEM 1A. Risk Factors.

Including the impact of EOG's 2012 crude oil derivative contracts and based on EOG's tax position, EOG's price sensitivity in 2012 for each $1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the related change in natural gas liquids price, is approximately $31 million for net income and $46 million for cash flows from operating activities. Including the impact of EOG's 2012 natural gas derivative contracts and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2012 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf increase or decrease in wellhead natural gas price is approximately $11 million for net income and $16 million for cash flows from operating activities. For a summary of EOG's financial commodity derivative contracts at February 24, 2012, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions. For a summary of EOG's financial commodity derivative contracts at December 31, 2011, see Note 11 to Consolidated Financial Statements.

Risk Management. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily collar, price swap, option and basis swap contracts, as a means to manage this price risk. See Note 11 to Consolidated Financial Statements. In addition to financial transactions, EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. Under the provisions of the Derivatives and Hedging Topic of the Accounting Standards Codification, these physical commodity contracts qualify for the normal purchases and normal sales exception and, therefore, are not subject to hedge accounting or mark-to-market accounting. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices. For a summary of EOG's financial commodity derivative contracts at February 24, 2012, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions. For a summary of EOG's financial commodity derivative contracts at December 31, 2011, see Note 11 to Consolidated Financial Statements.

All of EOG's crude oil and natural gas activities are subject to the risks normally incident to the exploration for, and development and production of, crude oil and natural gas, including blowouts, rig and well explosions, cratering, fires and loss of well control, each of which could result in damage to life, property and/or the environment. EOG's onshore and offshore operations are also subject to usual customary perils, including hurricanes and other adverse weather conditions. Moreover, EOG's activities are subject to governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. Losses and liabilities arising from such events could reduce revenues and increase costs to EOG to the extent not covered by insurance.

Insurance is maintained by EOG against some, but not all, of these risks in accordance with what EOG believes are customary industry practices and in amounts and at costs that EOG believes to be prudent and commercially practicable. Specifically, EOG maintains commercial general liability and excess liability coverage provided by third-party insurers for bodily injury or death claims resulting from an incident involving EOG's onshore or offshore operations (subject to policy terms and conditions). Moreover, in the event an incident with respect to EOG's onshore or offshore operations results in negative environmental effects, EOG maintains operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that EOG may incur from such an incident, including obligations, expenses or claims in respect of seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operators extra expense coverage would be EOG's primary coverage, with the commercial general liability and excess liability coverage referenced above also providing certain coverage to EOG. All of EOG's onshore and offshore drilling activities are conducted on a contractual basis with independent drilling contractors and other third-party service contractors. The indemnification and other risk allocation provisions included in such contracts are negotiated on a contract-by-contract basis and are each based on the particular circumstances of the services being provided and the anticipated operations.

In addition to the above-described risks, EOG's operations outside the United States are subject to certain risks, including the risk of increases in taxes and governmental royalties, changes in laws and policies governing the operations of foreign-based companies, expropriation of assets, unilateral or forced renegotiation or modification of existing contracts with governmental entities, currency restrictions and exchange rate fluctuations. Please refer to ITEM 1A. Risk Factors for further discussion of the risks to which EOG is subject.

Texas Severance Tax Rate Reduction. Natural gas production from qualifying Texas natural gas wells spudded or completed after August 31, 1996 is entitled to a reduced severance tax rate for the first 120 consecutive months of production. However, the cumulative value of the tax reduction cannot exceed 50 percent of the drilling and completion costs incurred on a well-by-well basis. For a discussion of the impact on EOG, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Operating and Other Expenses.

Executive Officers of the Registrant

The current executive officers of EOG and their names and ages (as of February 24, 2012) are as follows:

Name	Age	Position
Mark G. Papa	65	Chairman of the Board and Chief Executive Officer; Director
William R. Thomas	59	President
Gary L. Thomas	62	Chief Operating Officer
Fredrick J. Plaeger, II	58	Senior Vice President and General Counsel
Timothy K. Driggers	50	Vice President and Chief Financial Officer

Mark G. Papa was elected Chairman of the Board and Chief Executive Officer of EOG in August 1999, President and Chief Executive Officer and director in September 1998, President and Chief Operating Officer in September 1997 and President in December 1996, and was President-North America Operations from February 1994 to December 1996. Mr. Papa joined Belco Petroleum Corporation, a predecessor of EOG, in 1981. Mr. Papa is also a director of Oil States International, Inc., an oilfield service company, where he serves on the Compensation and Nominating and Corporate Governance committees. From July 2003 to April 2005, Mr. Papa served as a director of the general partner of Magellan Midstream Partners LP, a pipeline and terminal company, where he served as Chairman of the Compensation Committee and as a member of the Audit and Conflicts Committees. Mr. Papa is EOG's principal executive officer.

William R. Thomas was elected President in September 2011. He was elected Senior Vice President and General Manager of EOG's Fort Worth, Texas office in June 2004, Executive Vice President and General Manager of EOG's Fort Worth, Texas office in February 2007, Senior Executive Vice President, Exploitation in February 2011, and served as Senior Executive Vice President, Exploration from July 2011 to September 2011. Mr. Thomas joined a predecessor of EOG in January 1979.

Gary L. Thomas was elected Chief Operating Officer in September 2011. He was elected Executive Vice President, North America Operations in May 1998, Executive Vice President, Operations in May 2002, and served as Senior Executive Vice President, Operations from February 2007 to September 2011. He also previously served as Senior Vice President and General Manager of EOG's Midland, Texas office. Mr. Thomas joined a predecessor of EOG in July 1978.

Frederick J. Plaeger, II joined EOG as Senior Vice President and General Counsel in April 2007. He served as Vice President and General Counsel of Burlington Resources Inc., an independent oil and natural gas exploration and production company, from June 1998 until its acquisition by ConocoPhillips in March 2006. Mr. Plaeger engaged exclusively in leadership roles in professional legal associations from April 2006 until April 2007.

Timothy K. Driggers was elected Vice President and Chief Financial Officer in July 2007. He was elected Vice President and Controller of EOG in October 1999 and was subsequently named Vice President, Accounting and Land Administration in October 2000 and Vice President and Chief Accounting Officer in August 2003. Mr. Driggers is EOG's principal financial officer. Mr. Driggers joined EOG in October 1999.

ITEM 1A. Risk Factors

Our business and operations are subject to many risks. The risks described below may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the events or circumstances described below actually occurs, our business, financial condition, results of operations or cash flow could be materially and adversely affected and the trading price of our common stock could decline. The following risk factors should be read in conjunction with the other information contained herein, including the consolidated financial statements and the related notes. Unless the context requires otherwise, "we," "us" and "our" refer to EOG Resources, Inc. and its subsidiaries.

A substantial or extended decline in crude oil or natural gas prices would have a material and adverse effect on us.

Prices for crude oil and natural gas (including prices for natural gas liquids and condensate) fluctuate widely. Among the factors that can or could cause these price fluctuations are:

- the level of consumer demand;
- supplies of crude oil and natural gas;
- weather conditions and changes in weather patterns;
- domestic and international drilling activity;
- the availability, proximity and capacity of transportation facilities;
- worldwide economic and political conditions;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the nature and extent of governmental regulation (including environmental regulation and regulation of derivatives transactions and hedging activities) and taxation;
- the level and effect of trading in commodity futures markets, including trading by commodity price speculators and others; and

- the effect of worldwide energy conservation measures.

Our cash flow and results of operations depend to a great extent on the prevailing prices for crude oil and natural gas. Prolonged or substantial declines in crude oil and/or natural gas prices may materially and adversely affect our liquidity, the amount of cash flow we have available for our capital expenditures and other operating expenses, our ability to access the credit and capital markets and our results of operations.

In addition, if we expect significant sustained decreases in crude oil and natural gas prices in the future such that the expected future cash flow from our crude oil and natural gas properties falls below the net book value of our properties, we may be required to write down the value of our crude oil and natural gas properties. Any such future asset impairments could materially and adversely affect our results of operations and, in turn, the trading price of our common stock.

Drilling crude oil and natural gas wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reserves (including "dry holes"). As a result, we may not recover all or any portion of our investment in new wells.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled, the cost of such operations may increase and/or our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and changes in weather patterns;
- compliance with, or changes in, environmental laws and regulations relating to air emissions, waste disposal and hydraulic fracturing, laws and regulations imposing conditions and restrictions on drilling and completion operations and other laws and regulations, such as tax laws and regulations;
- the availability and timely issuance of required governmental permits and licenses;
- the availability of, costs associated with and terms of contractual arrangements for properties, including leases, pipelines, rail cars, crude oil hauling trucks and qualified drivers and related facilities and equipment to gather, process, compress, transport and market crude oil, natural gas and related commodities; and
- costs of, or shortages or delays in the availability of, drilling rigs, pressure pumping equipment and supplies, tubular materials, water resources, sand, disposal facilities, qualified personnel and other necessary equipment, supplies and services.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators in each case due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations. For related discussion of the risks and potential losses and liabilities inherent in our crude oil and natural gas operations generally, see the immediately following risk factor.

Our crude oil and natural gas operations involve many risks and expose us to potential losses and liabilities, and insurance may not fully protect us against these risks and potential losses and liabilities.

Our onshore and offshore operations are subject to all of the risks associated with exploring and drilling for, and producing, gathering, processing and transporting, crude oil and natural gas, including the risks of:

- well blowouts and cratering;
- loss of well control;
- crude oil spills, natural gas leaks and pipeline ruptures;

- pipe failures and casing collapses;
- uncontrollable flows of crude oil, natural gas, formation water or drilling fluids;
- releases of chemicals or other hazardous substances;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and other natural disasters;
- fires and explosions;

• terrorism or vandalism;
• formations with abnormal pressures; and
• malfunctions of gathering, processing and other equipment.

If any of these events occur, we could incur losses and liabilities as a result of:

• injury or loss of life;
• damage to, or destruction of, property, equipment and crude oil and natural gas reservoirs;
• pollution or other environmental damage;
regulatory investigations and penalties as well as clean-up and remediation responsibilities and costs;
• suspension or interruption of our operations, including due to injunction; and
• repairs necessary to resume operations.

We maintain insurance against many, but not all, such losses and liabilities in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. The occurrence of any of these events and any losses or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage, would reduce the funds available to us for our onshore and offshore exploration, exploitation, development and production activities and could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Our ability to sell and deliver our crude oil and natural gas production could be materially and adversely affected if we fail to obtain adequate gathering, processing, compression and transportation services.

The sale of our crude oil and natural gas production depends on a number of factors beyond our control, including the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities owned by third parties. These facilities may be temporarily unavailable to us due to market conditions, mechanical reasons or other factors or conditions, and may not be available to us in the future on terms we consider acceptable, if at all. Any significant change in market or other conditions affecting these facilities or the availability of these facilities, including due to our failure or inability to obtain access to these facilities on terms acceptable to us or at all, could materially and adversely affect our business and, in turn, our financial condition and results of operations.

If we fail to acquire or find sufficient additional reserves over time, our reserves and production will decline from their current levels.

The rate of production from crude oil and natural gas properties generally declines as reserves are produced. Except to the extent that we conduct successful exploration, exploitation and development activities, acquire additional properties containing reserves or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our reserves will decline as they are produced. Maintaining our production of crude oil and natural gas at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves, which could in turn impact our future cash flow and results of operations.

We incur certain costs to comply with government regulations, particularly regulations relating to environmental protection and safety, and could incur even greater costs in the future.

Our exploration, production and marketing operations are regulated extensively by federal, state and local governments and regulatory agencies, both domestically and in the foreign countries in which we do business, and are subject to interruption or termination by governmental and regulatory authorities based on environmental or other considerations. Moreover, we have incurred and will continue to incur costs in our efforts to comply with the requirements of environmental, safety and other regulations. Further, the regulatory environment in the oil and gas industry could change in ways that we cannot predict and that might substantially increase our costs of compliance and, in turn, materially and adversely affect our business, results of operations and financial condition.

Specifically, as an owner or lessee and operator of crude oil and natural gas properties, we are subject to various federal, state, local and foreign regulations relating to the discharge of materials into, and the protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution cleanup resulting from operations, subject us to liability for pollution damages and require suspension or cessation of operations in affected areas. Moreover, we are subject to the United States (U.S.) Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions. Changes in, or additions to, these regulations could lead to increased operating and compliance costs and, in turn, materially and adversely affect our business, results of operations and financial condition.

Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, we are also aware of legislation proposed by U.S. lawmakers and by the Canadian federal and provincial governments to reduce GHG emissions.

Additionally, there have been various proposals to regulate hydraulic fracturing at the federal level. Most onshore crude oil and natural gas wells drilled by EOG are completed and stimulated through the use of hydraulic fracturing. Currently, the regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements (such as the reporting and public disclosure of the chemical additives used in the fracturing process) and in additional operating restrictions. In addition to the possible federal regulation of hydraulic fracturing, some states and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells, testing of nearby water wells, restrictions on the access to and usage of water, disclosure of the chemical additives used in hydraulic fracturing operations and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Such federal and state permitting and disclosure requirements and operating restrictions and conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. Accordingly, our production of crude oil and natural gas could be materially and adversely affected. For additional discussion regarding climate change and hydraulic fracturing, see Environmental Regulation – United States and Environmental Regulation – Canada under ITEM 1. Business – Regulation.

We will continue to monitor and assess any proposed or new policies, legislation, regulations and treaties in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary. We are unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations and financial condition. For related discussion, see the risk factor below regarding the provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act with respect to regulation of derivatives transactions and entities (such as EOG) that participate in such transactions.

A portion of our crude oil and natural gas production may be subject to interruptions that could have a material and adverse effect on us.

A portion of our crude oil and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, as a result of accidents, weather conditions, loss of gathering, processing, compression or transportation facility access or field labor issues, or intentionally as a result of market conditions such as crude oil or natural gas prices that we deem uneconomic. If a substantial amount of our production is interrupted, our cash flow and, in turn, our results of operations could be materially and adversely affected.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower crude oil or natural gas prices. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

From time to time, we seek to acquire crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is duly diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to assess fully their deficiencies and potential. Even when problems with a property are identified, we often may assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as discussed further below), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

We have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms, if at all.

We make, and will continue to make, substantial capital expenditures for the acquisition, exploration, development and production of crude oil and natural gas reserves. We intend to finance our capital expenditures primarily through our cash flow from operations, commercial paper borrowings, sales of assets and borrowings under other uncommitted credit facilities and, to a lesser extent and if and as necessary, bank borrowings, borrowings under our revolving credit facility and public and private equity and debt offerings.

Lower crude oil and natural gas prices, however, would reduce our cash flow. Further, if the condition of the credit and capital markets materially declines, we might not be able to obtain financing on terms we consider acceptable, if at all. The weakness and volatility in domestic and global financial markets and economic conditions in recent years may increase the interest rates that lenders and commercial paper investors require us to pay and adversely affect our ability to finance our capital expenditures through equity or debt offerings or other borrowings. Moreover, a reduction in our cash flow (for example, as a result of lower crude oil and natural gas prices) and the corresponding adverse effect on our financial condition and results of operations may increase the interest rates that lenders and commercial paper investors require us to pay. In addition, a substantial increase in interest rates would decrease our net cash flows available for reinvestment. Any of these factors could have a material and adverse effect on our business, financial condition and results of operations.

The inability of our customers and other contractual counterparties to satisfy their obligations to us may have a material and adverse effect on us.

We have various customers for the crude oil, natural gas and related commodities that we produce as well as various other contractual counterparties, including several financial institutions and affiliates of financial institutions. Domestic and global economic conditions, including the financial condition of financial institutions generally, have weakened in recent years and remain relatively weak. In addition, there continues to be weakness and volatility in domestic and global financial markets relating to the credit crisis in recent years, and corresponding reaction by lenders to risk. These conditions and factors may adversely affect the ability of our customers and other contractual counterparties to pay amounts owed to us from time to time and to otherwise satisfy their contractual obligations to us, as well as their ability to access the credit and capital markets for such purposes.

Moreover, our customers and other contractual counterparties may be unable to satisfy their contractual obligations to us for reasons unrelated to these conditions and factors, such as the unavailability of required facilities or equipment due to mechanical failure or market conditions. Furthermore, if a customer is unable to satisfy its contractual obligation to purchase crude oil, natural gas or related commodities from us, we may be unable to sell such production to another customer on terms we consider acceptable, if at all, due to the geographic location of such production, the availability, proximity or capacity of transportation facilities or market or other factors and conditions.

The inability of our customers and other contractual counterparties to pay amounts owed to us and to otherwise satisfy their contractual obligations to us may materially and adversely affect our business, financial condition, results of operations and cash flow.

Competition in the oil and gas exploration and production industry is intense, and many of our competitors have greater resources than we have.

We compete with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and the equipment, materials, services and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market crude oil and natural gas. In addition, many of our competitors have financial and other resources substantially greater than those we possess and have established strategic long-term positions and strong governmental relationships in countries in which we may seek new or expanded entry. As a consequence, we may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights or in acquiring necessary services, equipment, supplies and personnel. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. We also face competition, to a lesser extent, from competing energy sources, such as alternative energy sources.

Reserve estimates depend on many interpretations and assumptions that may turn out to be inaccurate. Any significant inaccuracies in these interpretations and assumptions could cause the reported quantities of our reserves to be materially misstated.

Estimating quantities of liquids and natural gas reserves and future net cash flows from such reserves is a complex, inexact process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, made by our management and our independent petroleum consultants. Any significant inaccuracies in these interpretations or assumptions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated. Moreover, the data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

To prepare estimates of our economically recoverable liquids and natural gas reserves and future net cash flows from our reserves, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, many of which factors are or may be beyond our control. Our actual reserves and future net cash flows from such reserves most likely will vary from our estimates. Any significant variance, including any significant revisions to our existing reserve estimates, could materially and adversely affect our business, financial condition and results of operations and, in turn, the trading price of our common stock. For related discussion, see ITEM 2. Properties – Oil and Gas Exploration and Production – Properties and Reserves.

Weather and climate may have a significant and adverse impact on us.

Demand for crude oil and natural gas is, to a significant degree, dependent on weather and climate, which impacts, among other things, the price we receive for the commodities we produce and, in turn, our cash flow and results of operations. For example, relatively warm temperatures during a winter season generally result in relatively lower demand for natural gas (as less natural gas is used to heat residences and businesses) and, as a result, relatively lower prices for natural gas production.

In addition, our exploration, exploitation and development activities and equipment can be adversely affected by extreme weather conditions, such as winter storms, flooding and hurricanes in the Gulf of Mexico, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs, the installation and operation of gathering and production facilities and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. Such extreme weather conditions and changes in weather patterns may materially and adversely affect our business and, in turn, our financial condition and results of operations.

Our hedging activities may prevent us from benefiting fully from increases in crude oil and natural gas prices and may expose us to other risks, including counterparty risk.

We use derivative instruments (primarily financial collars, price swaps and basis swaps) to hedge the impact of fluctuations in crude oil and natural gas prices on our results of operations and cash flow. To the extent that we engage in hedging activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of increases in crude oil and natural gas prices above the prices established by our hedging contracts. In addition, our hedging activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts.

Recent federal legislation and related regulations regarding derivatives transactions could have a material and adverse impact on our hedging activities.

As discussed in the risk factor immediately above, we use derivative instruments to hedge the impact of fluctuations in crude oil and natural gas prices on our results of operations and cash flow. In 2010, Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which, among other matters, establishes a comprehensive framework for the regulation of derivatives, or "swaps." The U.S. Securities and Exchange Commission, which has jurisdiction over security-based swaps, and the Commodity Futures Trading Commission, which has jurisdiction over swaps, are in the process of adopting regulations to implement this new regulatory regime. Once implemented, entities such as EOG that enter into swaps will be subject to, among other provisions, swap recordkeeping and reporting requirements; position limits for certain referenced futures contracts in the major energy markets and economically equivalent futures, options and swaps; and, subject to certain exceptions which may be applicable to EOG, swap clearing, trade execution and margin requirements (i.e., collateral posting requirements). Our swap counterparties could be subject to even greater regulatory oversight and may be subject to regulated capital requirements.

The applicability of such provisions (and the availability of certain exemptions) to EOG, our hedging activities and our hedging counterparties is currently uncertain, as many of the implementing regulations have not been finalized. However, the legislation and related regulations could significantly increase our cost of compliance, increase the cost and alter the terms of derivatives transactions, and adversely impact the number and creditworthiness of available swap counterparties. All of this could impact our available liquidity, require us to divert funds away from our exploration, development and production activities (e.g., in order to satisfy margin/collateral posting requirements) and reduce our ability to hedge and otherwise manage our financial and commercial risks related to crude oil and natural gas price fluctuations. If we reduce our use of derivatives as a result of the legislation and related regulations, our results of operations may become more volatile and our cash flow may be less predictable, which could materially and adversely affect our ability to plan for and fund our capital expenditure requirements. Any of the foregoing consequences could have a material and adverse effect on our business, financial condition and results of operations.

We operate in other countries and, as a result, are subject to certain political, economic and other risks.

Our operations in jurisdictions outside the U.S. are subject to various risks inherent in foreign operations. These risks include, among other risks:

- increases in taxes and governmental royalties;
- changes in laws and policies governing operations of foreign-based companies;
- loss of revenue, equipment and property as a result of expropriation, acts of terrorism, war, civil unrest and other political risks;
- unilateral or forced renegotiation, modification or nullification of existing contracts with governmental entities;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and
- currency restrictions and exchange rate fluctuations.

Our international operations may also be adversely affected by U.S. laws and policies affecting foreign trade and taxation. The realization of any of these factors could materially and adversely affect our business, financial condition and results of operations.

Our business and prospects for future success depend to a significant extent upon the continued service and performance of our management team.

Our business and prospects for future success, including the successful implementation of our strategies and handling of issues integral to our future success, depend to a significant extent upon the continued service and performance of our management team. The loss of any member of our management team, and our inability to attract, motivate and retain substitute management personnel with comparable experience and skills, could materially and adversely affect our business, financial condition and results of operations.

Unfavorable currency exchange rate fluctuations could adversely affect our results of operations.

The reporting currency for our financial statements is the U.S. dollar. However, certain of our subsidiaries are located in countries other than the U.S. and have functional currencies other than the U.S. dollar. The assets, liabilities, revenues and expenses of certain of these foreign subsidiaries are denominated in currencies other than the U.S. dollar. To prepare our consolidated financial statements, we must translate those assets, liabilities, revenues and expenses into U.S. dollars at then-applicable exchange rates. Consequently, increases and decreases in the value of the U.S. dollar versus other currencies will affect the amount of these items in our consolidated financial statements, even if the amount has not changed in the original currency. These translations could result in changes to our results of operations from period to period. For the fiscal year ended December 31, 2011, approximately 5% of our net operating revenues related to operations of our foreign subsidiaries whose functional currency was not the U.S. dollar.

Terrorist activities and military and other actions could materially and adversely affect us.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. The U.S. government has at times issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. Any such actions and the threat of such actions could materially and adversely affect us in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in crude oil and natural gas prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business, financial condition and results of operations.

ITEM 1B. Unresolved Staff Comments

Not applicable.

ITEM 2. Properties

Oil and Gas Exploration and Production - Properties and Reserves

Reserve Information. For estimates of EOG's net proved and proved developed reserves of crude oil and condensate, natural gas liquids and natural gas, as well as discussion of EOG's proved undeveloped reserves, the qualifications of the preparers of EOG's reserve estimates, EOG's independent petroleum consultants and EOG's processes and controls with respect to its reserve estimates, see "Supplemental Information to Consolidated Financial Statements."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in Supplemental Information to Consolidated Financial Statements represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and condensate, natural gas liquids and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers normally vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate (upward or downward). Accordingly, reserve estimates are often different from the quantities ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. For related discussion, see ITEM 1A. Risk Factors.

In general, the rate of production from EOG's crude oil and natural gas properties declines as reserves are produced. Except to the extent EOG acquires additional properties containing proved reserves, conducts successful exploration, exploitation and development activities or, through engineering studies, identifies additional behind-pipe zones or secondary recovery reserves, the proved reserves of EOG will decline as reserves are produced. The volumes to be generated from future activities of EOG are therefore highly dependent upon the level of success in finding or acquiring additional reserves. For related discussion, see ITEM 1A. Risk Factors. EOG's estimates of reserves filed with other federal agencies agree with the information set forth in Supplemental Information to Consolidated Financial Statements.

Acreage. The following table summarizes EOG's developed and undeveloped acreage at December 31, 2011. Excluded is acreage in which EOG's interest is limited to owned royalty, overriding royalty and other similar interests.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	1,742,667	1,303,030	4,950,407	3,572,980	6,693,074	4,876,010
Canada	1,228,360	1,021,507	804,486	748,509	2,032,846	1,770,016
Trinidad	75,717	65,719	48,520	38,816	124,237	104,535
United Kingdom	8,797	2,570	118,333	94,730	127,130	97,300
China	130,546	130,546	-	-	130,546	130,546
Total	3,186,087	2,523,372	5,921,746	4,455,035	9,107,833	6,978,407

Most of our oil and gas leases, particularly in the United States, are subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. Company-wide, approximately 1.02 million net acres will expire in 2012, 0.9 million net acres will expire in 2013 and 0.6 million net acres will expire in 2014 if production is not established or we take no other action to extend the terms of the leases or concessions. In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

Producing Well Summary. EOG operated 15,772 gross and 13,977 net producing crude oil and natural gas wells at December 31, 2011. Gross crude oil and natural gas wells include 1,577 wells with multiple completions.

	Crude Oil		Natural Gas		Total
	Gross	Net	Gross	Net	Gross