EOG RESOURCES INC
Form 10-K
February 24, 2011

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, 2010

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, 2010: $24,920,717,309.

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, 254,279,287shares outstanding as of February 18, 2011.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2011 Annual Meeting of Stockholders to be filed within 120 days after December 31, 2010 are incorporated by reference into Part III of this report.

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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) 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, 2010, EOG's total estimated net proved reserves were 1,950 million barrels of oil equivalent (MMBoe), of which 386 million barrels (MMBbl) were crude oil and condensate reserves, 152 MMBbl were natural gas liquids reserves and 8,470 billion cubic feet (Bcf), or 1,412 MMBoe, were natural gas reserves (see Supplemental Information to Consolidated Financial Statements). At such date, approximately 82% of EOG's reserves (on a crude oil equivalent basis) were located in the United States, 11% in Canada and 7% in Trinidad. As of December 31, 2010, EOG employed approximately 2,290 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 focuses on the cost-effective utilization of advances in technology associated with the gathering, processing and interpretation of three-dimensional seismic data, the development of reservoir simulation models, the use of new and/or improved drill bits, mud motors and mud additives, horizontal drilling, formation logging techniques and reservoir stimulation/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. EOG also makes select strategic acquisitions that result in additional economies of scale or land positions which provide significant additional prospects. 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.

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, 2010, 30% of EOG's net proved United States and Canada reserves (on a crude oil equivalent basis) were crude oil and condensate and natural gas liquids and 70% 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 2010 and certain 2011 plans for EOG's United States and Canada operations.

United States. In April 2010, EOG announced its acreage holdings in the Eagle Ford play and in May 2010, EOG opened an office in San Antonio, Texas, to focus on more fully exploiting its 595,000 net acres in the Eagle Ford play. The Eagle Ford has distinguished itself among other resource plays in the United States as it has crude oil, wet gas and dry gas trends. The economics of the crude oil and wet gas trends make this play one of the most impactful resource plays in the United States under current economic conditions. EOG holds 520,000 net acres in the crude oil trend and 26,000 net acres in the wet gas trend. EOG significantly increased its activity in this play during 2010, drilling 96 net wells and completing 80 net wells with 12 rigs running at year-end. At year-end, the net daily production was approximately 17.3 thousand barrels per day (MBbld) of crude oil and condensate and natural gas liquids and 13.7 million cubic feet per day (MMcfd) of natural gas. EOG will focus its attention in 2011 on exploitation and development of the Eagle Ford play by drilling approximately 250 net wells and on the delineation of the full extent of our large oil-rich acreage position.

In 2010, EOG increased activity in the liquids-rich Barnett Shale Combo play of the Fort Worth Basin where production grew by approximately 230% above 2009 levels. During the year, EOG completed 184 net Barnett Combo wells and increased its drilling potential in this liquids-rich play by expanding the core area from approximately 90,000 net acres to 175,000 net acres. EOG also completed 166 net Barnett gas wells. EOG's total 2010 Barnett Shale average net daily production increased to approximately 23.2 MBbld of crude oil and condensate and natural gas liquids and 404 MMcfd of natural gas. For 2011, EOG will continue to focus on growing liquids production from the Barnett Combo with plans to complete to sales an additional 262 net Barnett Combo wells. EOG's activity in the natural gas portion of the Barnett will significantly decrease during 2011 with plans to complete approximately 24 net gas wells to sales. With a large acreage position of approximately 600,000 net acres in the Fort Worth Basin Barnett Shale and a history of strong drilling results, EOG plans to continue significant drilling for years in the future.

Throughout the Rocky Mountain area, EOG continued its focus on exploring and developing its crude oil properties. During 2010, EOG increased its development program in the Williston Basin by drilling 111 net wells in the Bakken and Three Forks plays, while increasing its acreage position to 600,000 net acres available for exploration and development. EOG currently holds approximately 2.0 million net acres in the Rocky Mountain area. Exploration and development activities increased in the Niobrara Formation in both the DJ (Colorado and Wyoming) and North Park (Colorado) Basins with 31 net wells drilled. In 2010, EOG drilled 76 net wells on its Uinta Basin natural gas acreage, a decrease from the prior year. Overall during 2010, EOG drilled 222 net wells throughout the Rocky Mountain area. Total production increased 3% primarily through a 20% increase in liquids production. The net average production for 2010 was 41.5 MBbld of crude oil and condensate and natural gas liquids and 212 MMcfd of natural gas. For 2011, EOG intends to maintain its activity level in the Bakken and Three Forks plays of the Williston Basin, along with further exploration and development of its Niobrara acreage position in the DJ, North Park and Powder River Basins. Our primary focus remains on exploiting and expanding our crude oil resource positions and drilling activity will remain limited on our core natural gas assets within the Rocky Mountain area. EOG plans to drill approximately 159 net wells throughout the Rocky Mountain area during 2011.

In 2010, EOG continued to expand its activities in the Mid-Continent area with continued growth and extension of the Western Anadarko Basin and Hugoton Deep core areas. For the year, EOG averaged net production of 5.8 MBbld of crude oil and condensate and natural gas liquids and 60 MMcfd of natural gas. Total crude oil and condensate and natural gas liquids volumes increased 9% in 2010 compared to 2009. In Southwest Kansas, EOG continued to focus on high potential targets in the Morrow and St. Louis formations in a broad area, which is part of the 900,000 gross acres EOG controls in the Hugoton Deep play. In the Western Anadarko Basin, EOG continued successful horizontal exploitation of the Cleveland sandstone, drilling 14 net wells with initial per-well production rates of approximately 350 barrels of oil per day (Bbld), gross. Since 2002, EOG has drilled over 220 net wells in this play and holds approximately 65,000 acres throughout the trend. In addition, EOG made new discoveries in both the Marmaton Sandstone and Cherokee Skinner formations. A total of 16 net wells were drilled in 2010 in these formations with initial per-well production rates averaging 450 Bbld, gross. These new liquids-rich plays will be exploited by drilling approximately 32 net wells in 2011. EOG holds approximately 720,000 net acres in the Mid-Continent area.

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In 2010, EOG drilled 34 net wells in the Permian Basin to test the Leonard-Avalon Shale, Bone Spring, Wolfcamp and Wolfberry formations. EOG is well positioned in three of these emerging plays: the Leonard-Avalon Shale and Bone Spring plays in the Delaware Basin and the Wolfcamp Shale play in the Midland Basin. Production for the year 2010 averaged 7.8 MBbld, net, of crude oil and condensate and natural gas liquids and 62 MMcfd, net, of natural gas. EOG now holds approximately 540,000 net acres throughout the Permian Basin, with approximately 120,000 acres within the Wolfcamp Shale formation and 120,000 acres within the limits of the Bone Spring and Leonard-Avalon formations. In 2011, EOG plans to continue the development, expansion and enhancement of the Wolfcamp, Leonard-Avalon and Bone Spring plays, while continuing to acquire strategic acreage positions to test new play concepts. Approximately 52 net Permian Basin wells are planned during 2011.

In the South Texas area, EOG drilled 48 net wells in 2010. Net production during 2010 averaged 6.8 MBbld of crude oil and condensate and natural gas liquids and 171 MMcfd of natural gas. EOG's activity was focused in Webb, Zapata, San Patricio, Nueces, Brooks and Kenedy Counties. EOG continued exploitation of the Lobo and Roleta sands, adding net reserves of 0.9 MMBbl of crude oil and condensate and natural gas liquids and 25.4 Bcf of natural gas. EOG continued developing reserves at Indian Point and East White Point under the Nueces Bay. EOG also exploited the liquids-rich Frio and Vicksburg trends in Brooks and Kenedy Counties, drilling 14 net wells in this 310,000 gross acre area which includes surrounding counties. EOG holds approximately 550,000 net acres in South Texas. Approximately 61 net wells are planned during 2011 for South Texas.

In the Upper Gulf Coast region, EOG drilled 63 net wells and averaged 206 MMcfd of natural gas and 2.6 MBbld of crude oil and condensate and natural gas liquids production in 2010. The Haynesville and Bossier Shale plays located near the Texas-Louisiana border were major growth drivers for EOG. The program has grown from drilling 13 net wells in 2009 to 53 net wells in 2010. EOG established a new Texas "sweet spot" in 2010 with exceptional well results, including numerous wells where initial production rates exceeded 20 MMcfd of natural gas. EOG now controls 183,000 net acres in this play and most of this acreage is within a well-defined production sweet spot. EOG holds approximately 390,000 net acres in the Upper Gulf Coast region. Approximately 45 net wells are planned during 2011 for the Upper Gulf Coast region.

During 2010, EOG continued the development of its Pennsylvania Marcellus Shale acreage, drilling a total of 33 net wells, including 18 net wells in Bradford County in northeast Pennsylvania which will be completed in 2011. The remaining 15 net wells were drilled in North Central Pennsylvania as part of EOG's joint venture with Seneca Resources Corporation. EOG holds a 50% working interest and is operator of this joint venture. Most of these joint venture wells have been completed and are producing. Several wells were turned to sales at rates in excess of 8 MMcfd, a substantial improvement from previous years. This rate increase is attributable to new completion procedures that were implemented in 2010. During 2010, EOG's production from the Marcellus Shale averaged 12 MMcfd, net. In 2011, EOG will continue to develop the Marcellus Shale by drilling an estimated 30 net wells. Those wells will be split between the joint venture area and Bradford County. EOG currently holds in excess of 200,000 net acres in the Pennsylvania Marcellus Shale.

At December 31, 2010, EOG held approximately 4.4 million net undeveloped acres in the United States.

During 2010, EOG continued the expansion of its gathering and processing activities in the Barnett Shale play of North Texas and the Bakken and Three Forks plays of North Dakota. In the Barnett Combo play, EOG expanded its natural gas processing plant capacity from 40 MMcfd to 80 MMcfd. EOG also continued its expansion of its Barnett Shale gathering system to transport production to its processing plant.

In the North Dakota Bakken play, EOG continued the expansion of its gathering system in the Bakken Core area, and committed to a third-party gatherer for the installation of a gathering system for its Bakken Lite area. The Bakken Lite system is expected to become operational in mid-2011. During February 2010, EOG placed in service a 76-mile, 12-inch diameter "dense phase" natural gas gathering pipeline connecting its Stanley, North Dakota, condensate recovery plant and gathering system with the Alliance Pipeline, near Upham, North Dakota. The Alliance Pipeline transports natural gas to the Chicago, Illinois, area.

At year-end 2010, the combined throughput of these gathering systems was approximately 80 MMcfd of natural gas. EOG expects to continue expanding its gathering and processing facilities to accommodate the drilling activity in the Barnett Shale and Bakken plays. The North Texas systems total over 80 miles of 8-inch, 10-inch and 20-inch diameter pipe, while the North Dakota system totals over 320 miles of 8-inch and 12-inch pipe.

Additionally, in support of its operations in the Williston Basin, EOG continued to increase usage of its crude oil loading facility near Stanley, North Dakota, transporting both its production and third-party production. Using this facility, EOG loaded 148 unit trains with crude oil for transport to Stroud, Oklahoma during 2010. Each unit train typically consists of 100 cars and has a total aggregate capacity of approximately 68,000 barrels of crude oil. In Stroud, Oklahoma, EOG owns a crude oil offloading facility and a pipeline to transport the crude oil to the Cushing, Oklahoma, trading hub. These facilities are now fully operational, with a capacity to transport approximately 70 MBbld of crude oil. As a part of these facilities, EOG also owns and operates approximately 24 miles of 8-inch and 12-inch crude oil pipeline.

Canada. EOG conducts operations through its wholly-owned subsidiary, EOG Resources Canada Inc. (EOGRC), from its offices in Calgary, Alberta. During 2010, EOGRC continued its focus on horizontal crude oil growth, mainly through its drilling activity in Waskada, Manitoba, and Highvale, Alberta, and on bigger target horizontal natural gas in the Horn River Basin of British Columbia. During 2010, EOGRC drilled or participated in 114 net wells, 108 of which were horizontal wells and six of which were vertical wells. Correspondingly, net crude oil and condensate and natural gas liquids production increased by 47% to 7.6 MBbld and net natural gas production decreased 11% to 200 MMcfd. The natural gas production volume decline also reflects the sales of several shallow gas properties consummated in the fourth quarter of 2010. EOG received proceeds of approximately $344 million from these sales transactions. The focus on crude oil production growth will continue in 2011 with 85 net wells planned in a combination of plays from the continued development in Manitoba and new targets in Alberta. EOG plans to drill four wells in the Horn River Basin in 2011.

During the second quarter of 2010, EOGRC agreed to acquire all of the outstanding common stock of Galveston LNG Inc., a Calgary-based corporation which, through its wholly-owned subsidiary, Kitimat LNG Inc. and affiliates, owns 49 percent of the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, about 405 miles north of Vancouver, British Columbia. Planned capacity of the proposed Kitimat LNG terminal is about 700 million cubic feet of natural gas per day or five million metric tons of LNG per year. Preliminary total construction costs, currently estimated to be approximately $3 billion (Canadian), will be revised at the conclusion of front-end engineering and design. In addition, Galveston LNG Inc. also owns a 24.5 percent interest in the proposed Pacific Trail Pipelines (PTP), a total estimated $1 billion (Canadian), 300-mile project, originating at Summit Lake, British Columbia. The pipeline is intended to link Western Canada's natural gas producing regions to the Kitimat LNG terminal. An affiliate of Apache Corporation owns 51 percent of the planned Kitimat LNG terminal and a 25.5 percent interest in PTP and will be the operator of the Kitimat LNG terminal. During the fourth quarter of 2010, upon the achievement of certain commercial and regulatory milestones, EOGRC paid $210 million to complete the acquisition of Galveston LNG Inc. In connection with the acquisition, EOG recorded intangible assets related to certain leases, permits and other contracts. During the first quarter of 2011, EOGRC entered into an agreement to purchase an additional 24.5 percent interest in PTP for $24.5 million (subject to customary closing conditions). A portion of the purchase price ($14.7 million) will be paid at closing with the remaining amount ($9.8 million) to be paid contingent on the decision to proceed with the construction of the Kitimat LNG terminal. Subsequent to closing, EOGRC's ownership interest will be 49 percent. An affiliate of Apache Corporation entered into an agreement to purchase the remaining 25.5 percent interest in PTP, which will increase its ownership interest to 51 percent of the proposed project.

At December 31, 2010, EOGRC held approximately 1.3 million net undeveloped acres in Canada.

Operations Outside the United States and Canada

EOG has operations in Trinidad, the United Kingdom North Sea and East Irish Sea and the China Sichuan Basin, and is evaluating additional exploration, development and exploitation opportunities in these and other 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 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. In the Pelican Field, EOG drilled a successful exploratory well that began producing in the first quarter of 2010. In Block 4(a), EOG completed installation of offshore facilities and began its development drilling program in December 2010 to supply natural gas under a contract with the National Gas Company of Trinidad and Tobago (NGC) into the North Eastern Offshore (NEO) pipeline being installed by NGC. EOG is sourcing the natural gas for this contract from its existing fields until the NEO pipeline is completed. Sales under the contract commenced on January 1, 2010.

Given EOG's current level of equity ownership in CNCL and N2000 and its ability to exercise significant influence over certain material actions, it accounts for these investments using the equity method. During 2010, EOG recognized equity income of $5 million and received cash dividends of $6 million from CNCL and recognized equity income of $8 million and received cash dividends of $10 million from N2000.

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 approximately 500 MMcfd (345 MMcfd, net) of natural gas, under current economic conditions, for at least the next three years. EOG intends to fulfill these natural gas delivery obligations by using production from existing reserves. Crude oil and condensate from EOG's Trinidad operations currently is sold to the Petroleum Company of Trinidad and Tobago.

In 2010, EOG's average net production from Trinidad was 341 MMcfd of natural gas and 4.7 MBbld of crude oil and condensate.

At December 31, 2010, 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 49/16f, located in the Southern Gas Basin of the North Sea. During 2010, production continued in the Valkyrie field in the Southern Gas Basin.

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. The last well in the Arthur Field ceased production in 2010.

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 expects to submit 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 by the end of 2011. The operator and partners are currently negotiating processing and transportation terms with export infrastructure owners.

In 2009, EOGUK drilled a successful exploratory well in its East Irish Sea blocks. 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 2010, feasibility and front-end engineering design studies were completed, and all principal contracts are currently being negotiated for the development plan. A field development plan for the Conwy field was submitted to the DECC in the first quarter of 2011 and a separate plan is expected to be submitted for the Corfe field before the end of the first quarter of

2011. Regulatory approval of both plans is expected by the end of 2011. Installation of pipelines, drilling of development wells and initial production are planned for 2012. Two additional exploratory wells offsetting the Conwy field were drilled in the first quarter of 2010. Both wells were unsuccessful. The licenses for the East Irish Sea blocks were awarded to EOGUK in 2007.

In 2010, production averaged 4 MMcfd of natural gas, net, in the United Kingdom.

At December 31, 2010, EOG held approximately 190,000 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 2010, EOG drilled four horizontal wells, one of which was completed in 2010 and another which was completed in January 2011. In addition, EOG completed a horizontal well that was originally drilled in 2009. The wells completed in 2010 began production in the first and second quarters of 2010. EOG plans to complete two wells during the second quarter of 2011. EOG expects to complete its evaluation of the economic viability of this project during the first half of 2011.

In 2010, production averaged 10 MMcfd of natural gas, net, in China.

At December 31, 2010, EOG held approximately 130,000 net acres in China.

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 2010, 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 2011, the pricing mechanism for such production is expected to remain the same.

In 2010, 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 the United States Henry Hub market prices. The pricing mechanisms for these contracts in Trinidad are expected to remain the same in 2011.

In 2010, all wellhead natural gas volumes from the United Kingdom were sold on the spot market. The 2011 marketing strategy for the wellhead natural gas volumes from the United Kingdom is expected to remain the same.

In 2010, 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 2011.

In certain instances, EOG purchases and sells third-party natural gas production in order to balance firm transportation capacity with production in certain areas.

During 2010, no single purchaser accounted for 10% or more of EOG's crude oil and condensate, natural gas liquids and natural gas 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.

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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, 2010, 2009 and 2008.

Year Ended December 31	2010	2009	2008
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	63.2	47.9	39.5
Canada	6.7	4.1	2.7
Trinidad	4.7	3.1	3.2
Other International (2)	0.1	0.1	0.1
Total	74.7	55.2	45.5
Natural Gas Liquids Volumes (MBbld) (1)			
United States	29.5	22.5	15.0
Canada	0.9	1.1	1.0
Total	30.4	23.6	16.0
Natural Gas Volumes (MMcfd) (1)			
United States	1,133	1,134	1,162
Canada	200	224	222
Trinidad	341	273	218
Other International (2)	14	14	17
Total	1,688	1,645	1,619
Crude Oil Equivalent Volumes (MBoed) (3)			
United States	281.5	259.4	248.4
Canada	40.9	42.6	40.6
Trinidad	61.5	48.5	39.5
Other International (2)	2.5	2.4	2.8
Total	386.4	352.9	331.3
Total MMBoe (3)	141.1	128.8	121.3
Average Crude Oil and Condensate Prices ($/Bbl) (4)			
United States	$74.88	$54.42	$87.68
Canada	72.66	57.72	89.70
Trinidad	68.80	50.85	92.90
Other International (2)	73.11	53.07	99.30
Composite	74.29	54.46	88.18
Average Natural Gas Liquids Prices ($/Bbl) (4)			
United States	$41.68	$30.03	$53.33
Canada	43.40	30.49	54.77
Composite	41.73	30.05	53.42
Average Natural Gas Prices ($/Mcf) (4)			
United States	$4.30	$3.72	$8.22
Canada	3.91	3.85	7.64
Trinidad	2.65	1.73	3.58
Other International (2)	4.90	4.34	8.18
Composite	3.93	3.42	7.51

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

(2) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's 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 liquefied natural gas imported into the United States from other countries, and 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) and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) (formerly, the Minerals Management Service), both 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 BOEMRE.

BLM and BOEMRE 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 BOEMRE). Such offshore operations are subject to numerous regulatory requirements, including the need for prior BOEMRE 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 removal of all production facilities. Under certain circumstances, the BOEMRE 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 the 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 the FERC 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 our 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 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 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, results of operations or competitive position. 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, results of operations and competitive position.

Climate Change. EOG is aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, EOG is also aware of legislation proposed by United States lawmakers to reduce GHG emissions and a recent U.S. EPA rulemaking that 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 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 business, results of operations, financial condition and competitive position.

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 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. The makeup of the fluid used in the hydraulic fracturing process is typically more than 99% water and sand, and less than 1% 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 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 recycled 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 ensure compliance with all applicable regulations. 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.

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 these federal proposals, some states and local governments 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; 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.

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 business, results of operations, financial condition and competitive position.

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 to 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, results of operations or competitive position. 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, results of operations and competitive position.

As noted above, EOG is aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. Canada is a signatory to the United Nations Framework Convention on Climate Change (also known as the Kyoto Protocol). 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 recently committed to moving forward with legislation enabling the creation of a cap and trade system to reduce GHG emissions in Manitoba.

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 within that country. EOG currently has operations in Trinidad, the United Kingdom and China.

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 business, results of operations, financial condition and competitive position. 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 2010 than in prior years and is expected to comprise an even larger portion in 2011. Average crude oil and condensate prices received by EOG for production in the United States and Canada increased by 37% in 2010, decreased by 38% in 2009 and increased by 28% in 2008, each as compared to the immediately preceding year. The average New York Mercantile Exchange (NYMEX) crude oil strip price for 2011 has increased approximately 3% subsequent to December 31, 2010. Average United States and Canada wellhead natural gas prices have fluctuated, at times rather dramatically, during the last three years. These fluctuations resulted in a 13% increase in the average wellhead natural gas price received by EOG for production in the United States and Canada in 2010, a decrease of 54% in 2009 and an increase of 30% in 2008, each as compared to the immediately preceding year. The average NYMEX natural gas strip price for 2011 has decreased by approximately 9% since December 31, 2010. Due to the many uncertainties associated with the world political environment, the availabilities of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, EOG is unable to predict what changes may occur in crude oil and condensate, natural gas liquids, natural gas, ammonia and methanol 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 2011 crude oil hedges and based on EOG's tax position, EOG's price sensitivity in 2011 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 $26 million for net income and $38 million for cash flows from operating activities. Including the impact of EOG's 2011 natural gas hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2011 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 $19 million for net income and $28 million for cash flows from operating activities. For information regarding EOG's crude oil and natural gas hedge positions as of December 31, 2010, 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 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, 2011, 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, 2010, 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. With regard to offshore operations, all of EOG's 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 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 and 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, 2011) are as follows:

Name	Age	Position
Mark G. Papa	64	Chairman of the Board and Chief Executive Officer; Director
Loren M. Leiker	57	Senior Executive Vice President, Exploration
Gary L. Thomas	61	Senior Executive Vice President, Operations
William R. Thomas	58	Senior Executive Vice President, Exploitation
Fredrick J. Plaeger, II	57	Senior Vice President and General Counsel
Timothy K. Driggers	49	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.

Loren M. Leiker was elected Senior Executive Vice President, Exploration in February 2007. He was elected Executive Vice President, Exploration in May 1998 and was subsequently named Executive Vice President, Exploration and Development in January 2000. He was previously Senior Vice President, Exploration. Mr. Leiker joined EOG in April 1989.

Gary L. Thomas was elected Senior Executive Vice President, Operations in February 2007. He was elected Executive Vice President, North America Operations in May 1998 and was subsequently named Executive Vice President, Operations in May 2002. He was previously Senior Vice President and General Manager of EOG's Midland, Texas office. Mr. Thomas joined a predecessor of EOG in July 1978.

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

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 fluctuate widely. Among the factors that can 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 liquefied natural gas, and alternative energy sources;
- the nature and extent of governmental regulation and taxation, including environmental regulations;
-

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 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 reservoirs. 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 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, 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, 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 may materially and adversely affect 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 at the federal, state and local levels, as well as by the governments and regulatory agencies 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.

We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. 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. 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 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 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. 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 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.

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 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. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs 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 a buyer 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 and borrowings under other uncommitted credit facilities and, to a lesser extent and if and as necessary, bank borrowings, borrowings under our revolving credit facilities 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. 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 liquefied natural gas imported into the U.S. from other countries, and 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 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.

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.

We do not insure against all potential losses and could be materially and adversely affected by unexpected liabilities or unexpected levels of liability.

The exploration for, and production and transportation of, crude oil and natural gas can be hazardous, involving natural disasters and other unforeseen occurrences such as blowouts, cratering, fires and loss of well control, which can damage or destroy wells or production facilities, result in injury or death, and damage property and the environment. Moreover, our onshore and offshore operations are subject to customary perils, including hurricanes and other adverse weather conditions. We maintain insurance against many, but not all, potential losses or liabilities arising from our operations 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 costs 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 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 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, 2010, approximately 8% 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

None.

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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, 2010. 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	1,787,931	1,325,254	6,187,339	4,403,325	7,975,270	5,728,579
Canada	1,225,970	1,024,942	1,318,441	1,258,372	2,544,411	2,283,314
Trinidad	72,951	64,336	48,520	38,816	121,471	103,152
United Kingdom	9,143	2,674	218,242	189,515	227,385	192,189
China	130,546	130,546	-	-	130,546	130,546
Total	3,226,541	2,547,752	7,772,542	5,890,028	10,999,083	8,437,780

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 not exceeding three years. Company-wide, approximately 1,045,713 net acres will expire in 2011, 1,407,179 net acres will expire in 2012 and 1,092,688 net acres will expire in 2013 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. The following table reflects EOG's ownership in producing crude oil and natural gas wells at December 31, 2010. EOG operated 15,951 gross and 14,114 net producing crude oil and natural wells. Gross crude oil and natural gas wells include 2,386 wells with multiple completions.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	2,198	1,497	8,360	6,578	10,558	8,075
Canada	607	503	7,009	6,334	7,616	6,837
Trinidad	13	10	22	18	35	28
United Kingdom	-	-	1	-	1	-
China	-	-	24	24	24	24
Total	2,818	2,010	15,416	12,954	18,234	14,964

Drilling and Acquisition Activities. During the years ended December 31, 2010, 2009 and 2008, EOG expended $5.5 billion, $3.9 billion and $5.1 billion, respectively, for exploratory and development drilling and acquisition of leases and producing properties, including asset retirement obligations of $72 million, $84 million and $181 million, respectively. The following tables set forth the results of the gross crude oil and natural gas wells drilled and completed for the years ended December 31, 2010, 2009 and 2008:

	Gross Developed Wells Completed				Gross Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2010								
United States	589	448	32	1,069	19	8	10	37
Canada	128	25	-	153	1	-	-	1
Trinidad	-	-	-	-	-	1	-	1
United Kingdom	-	-	-	-	-	-	3	3
China	-	-	-	-	-	2	-	2
Total	717	473	32	1,222	20	11	13	44
2009								
United States	195	407	26	628	22	23	7	52
Canada	38	60	-	98	3	-	-	3
United Kingdom	-	-	-	-	1	-	1	2
Total	233	467	26	726	26	23	8	57
2008								
United States	193	1,002	50	1,245	37	37	9	83
Canada	30	496	-	526	-	7	-	7
Total	223	1,498	50	1,771	37	44	9	90

The following tables set forth the results of the net crude oil and natural gas wells drilled and completed for the years ended December 31, 2010, 2009 and 2008:

	Net Developed Wells Completed				Net Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2010								
United States	459	374	29	862	16	7	10	33
Canada	128	25	-	153	1	-	-	1
Trinidad	-	-	-	-	-	1	-	1
United Kingdom	-	-	-	-	-	-	3	3
China	-	-	-	-	-	2	-	2
Total	587	399	29	1,015	17	10	13	40
2009								
United States	143	351	22	516	14	17	6	37
Canada	38	48	-	86	3	-	-	3
United Kingdom	-	-	-	-	1	-	1	2
Total	181	399	22	602	18	17	7	42
2008								
United States	145	820	47	1,012	19	31	9	59
Canada	26	441	-	467	-	7	-	7
Total	171	1,261	47	1,479	19	38	9	66

EOG participated in the drilling of wells that were in progress at the end of the period as set out in the table below for the years ended December 31, 2010, 2009 and 2008:

	Wells in Progress at end of Period					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
United States	243	205	277	239	218	187
Canada	1	1	5	4	3	3
Trinidad	-	-	1	1	-	-
United Kingdom	3	2	1	-	2	1
China	4	4	4	4	-	-
Total	251	212	288	248	223	191

EOG acquired wells, which includes the acquisition of additional interests in certain wells in which EOG previously owned an interest, as set out in the tables below for the years ended December 31, 2010, 2009 and 2008:

	Gross Acquired Wells			Net Acquired Wells		
	Crude Oil	Natural Gas	Total	Crude Oil	Natural Gas	Total
2010						
Canada	1	-	1	1	-	1
Total	1	-	1	1	-	1
2009						
United States	133	579	712	126	243	369
Canada	-	2	2	-	1	1
Total	133	581	714	126	244	370
2008						
United States	1	14	15	1	13	14
Canada	-	66	66	-	59	59
Trinidad	8	-	8	6	-	6
China	-	22	22	-	22	22
Total	9	102	111	7	94	101

All of EOG's drilling activities are conducted on a contractual basis with independent drilling contractors. EOG does not own drilling equipment. EOG's other property, plant and equipment primarily includes gathering, transportation and processing infrastructure assets which support EOG's exploration and production activities.

ITEM 3. Legal Proceedings

The information required by this Item is set forth under the "Contingencies" caption in Note 7 of Notes to Consolidated Financial Statements and is incorporated by reference herein.

PART II

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

EOG's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "EOG." The following table sets forth, for the periods indicated, the high and low sales price per share for EOG's common stock, as reported by the NYSE, and the amount of the cash dividend declared per share. The quarterly cash dividend on EOG's common stock has historically been declared in the quarter immediately preceding the quarter of payment and paid on January 31, April 30, July 31 and October 31 of each year (or, if such day is not a business day, the immediately preceding business day).

		Price Range		
		High	Low	Dividend Declared
2010				
	First Quarter	$ 100.44	$ 86.78	$ 0.155
	Second Quarter	114.95	93.28	0.155
	Third Quarter	108.47	85.42	0.155
	Fourth Quarter	102.06	86.00	0.155
2009				
	First Quarter	$ 72.83	$ 45.03	$ 0.145
	Second Quarter	79.12	53.09	0.145
	Third Quarter	84.43	60.29	0.145
	Fourth Quarter	101.76	79.37	0.145

On February 17, 2011, EOG's Board of Directors (Board) increased the quarterly cash dividend on the common stock from the current $0.155 per share to $0.16 per share effective beginning with the dividend to be paid on April 29, 2011 to stockholders of record as of April 15, 2011.

As of February 15, 2011, there were approximately 1,800 record holders and approximately 163,000 beneficial owners of EOG's common stock.

EOG currently intends to continue to pay quarterly cash dividends on its outstanding shares of common stock in the future. However, the determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other factors, the financial condition, cash flow, level of exploration and development expenditure opportunities and future business prospects of EOG.

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

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs (2)
October 1, 2010 - October 31, 2010	6,476	$ 98.38	-	6,386,200
November 1, 2010 - November 30, 2010	2,628	92.91	-	6,386,200
December 1, 2010 - December 31, 2010	1,258	91.89	-	6,386,200
Total	10,362	96.21		

(1) The 10,362 total shares for the quarter ended December 31, 2010 and the 115,120 shares for the full year 2010 consist solely of shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock or restricted stock unit grants or (ii) in payment of the exercise price of employee stock options. These shares do not count against the 10 million aggregate share repurchase authorization of EOG's Board discussed below.

(2) In September 2001, the Board authorized the repurchase of up to 10,000,000 shares of EOG's common stock. During 2010, EOG did not repurchase any shares under the Board-authorized repurchase program.

Comparative Stock Performance

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically requests that such information be treated as "soliciting material" or specifically incorporates such information by reference into such a filing.

The performance graph shown below compares the cumulative five-year total return to stockholders on EOG's common stock as compared to the cumulative five-year total returns on the Standard and Poor's 500 Index (S&P 500) and the Standard and Poor's 500 Oil & Gas Exploration & Production Index (S&P O&G E&P). The comparison was prepared based upon the following assumptions:

1. $100 was invested on December 31, 2005 in each of the following: Common Stock of EOG, the S&P 500 and the S&P O&G E&P.
2. Dividends are reinvested.

Comparison of Five-Year Cumulative Total Returns*
EOG, S&P 500 and S&P O&G E&P
(Performance Results Through December 31, 2010)

*Cumulative total return assumes reinvestment of dividends.

	2005	2006	2007	2008	2009	2010
EOG	$100.00	$85.38	$122.57	$91.91	$135.44	$127.99
S&P 500	$100.00	$113.62	$117.63	$72.36	$89.33	$100.75
S&P O&G E&P	$100.00	$104.65	$151.15	$98.91	$140.55	$153.58

ITEM 6. Selected Financial Data
(In Thousands, Except Per Share Data)

Year Ended December 31	2010	2009	2008	2007	2006
Statement of Income Data:					
Net Operating Revenues	$6,099,896	$4,786,959	$7,127,143	$4,239,303	$3,928,641
Operating Income	$523,319	$970,841	$3,767,185	$1,648,396	$1,903,553
Net Income	$160,654	$546,627	$2,436,919	$1,089,918	$1,299,885
Preferred Stock Dividends	-	-	443	6,663	10,995
Net Income Available to Common Stockholders	$160,654	$546,627	$2,436,476	$1,083,255	$1,288,890
Net Income Per Share Available to Common Stockholders					
Basic	$0.64	$2.20	$9.88	$4.45	$5.33
Diluted	$0.63	$2.17	$9.72	$4.37	$5.24
Dividends Per Common Share	$0.62	$0.58	$0.51	$0.36	$0.24
Average Number of Common Shares					
Basic	250,876	248,996	246,662	243,469	241,782
Diluted	254,500	251,884	250,542	247,637	246,100

At December 31	2010	2009	2008	2007	2006
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$18,680,900	$16,139,225	$13,657,302	$10,429,254	$7,944,047
Total Assets	21,624,233	18,118,667	15,951,226	12,088,907	9,402,160
Long-Term Debt and Current Portion of Long-Term Debt	5,223,341	2,797,000	1,897,000	1,185,000	733,442
Total Stockholders' Equity	10,231,632	9,998,042	9,014,497	6,990,094	5,599,671

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

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

Net income available to common stockholders for 2010 totaled $161 million as compared to $547 million for 2009. At December 31, 2010, EOG's total estimated net proved reserves were 1,950 million barrels of oil equivalent (MMBoe), an increase of 154 MMBoe from December 31, 2009.

Operations

Several important developments have occurred since January 1, 2010.

United States and Canada. EOG's effort to identify plays with larger reserve potential has proven a successful supplement to its base development and exploitation program in the United States and Canada. EOG continues to drill numerous wells in large acreage plays, which in the aggregate are expected to contribute substantially to EOG's crude oil and natural gas production. EOG has placed an emphasis on applying its horizontal drilling expertise gained in natural gas resource plays to unconventional crude oil reservoirs. In 2010, EOG focused its efforts on developing its existing North American crude oil and condensate and natural gas liquids acreage and capturing additional North American horizontal crude oil plays. During 2010, the North Dakota Bakken and Fort Worth Basin Barnett Shale areas produced an increased amount of crude oil and condensate and natural gas liquids as compared to 2009. EOG holds approximately 520,000 net acres in the mature oil window of the Eagle Ford Shale Play near San Antonio, Texas, where it drilled 96 net wells and completed 80 net wells in 2010. EOG averaged 15.1 thousand barrels per day (MBbld) of crude oil and condensate and natural gas liquids production in this play in December 2010 and expects crude oil production from this play to continue to grow in 2011. In Canada, EOG departed from its historical vertical shallow natural gas drilling program to focus on bigger target horizontal natural gas growth in the Horn River Basin and horizontal crude oil growth within existing legacy fields, mainly in Waskada, Manitoba and Highvale, Alberta. In addition, EOG continues to evaluate certain potential exploration and development prospects. Production in the United States and Canada accounted for approximately 83% of total company production in 2010 as compared to 86% in 2009. For 2010, crude oil and condensate and natural gas liquids production accounted for approximately 27% of total company production as compared to 22% for 2009. Based on current trends, EOG expects its 2011 crude oil and condensate and natural gas liquids production to increase both in total and as a percentage of total company production as compared to 2010. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

During the second quarter of 2010, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOGRC), agreed to acquire all of the outstanding common stock of Galveston LNG Inc., a Calgary-based corporation which, through its wholly-owned subsidiary, Kitimat LNG Inc. and affiliates, owns 49 percent of the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, about 405 miles north of Vancouver, British Columbia. Planned capacity of the proposed Kitimat LNG terminal is about 700 million cubic feet of natural gas per day or five million metric tons of LNG per year. Preliminary total construction costs, currently estimated to be approximately $3 billion (Canadian), will be revised at the conclusion of front-end engineering and design. In addition, Galveston LNG Inc. also owns a 24.5 percent interest in the proposed Pacific Trail Pipelines (PTP), a total estimated $1 billion (Canadian), 300-mile project, originating at Summit Lake, British Columbia. The pipeline is intended to link Western Canada's natural gas producing regions to the Kitimat LNG terminal. An affiliate of Apache Corporation owns 51 percent of the planned Kitimat LNG terminal and a 25.5 percent interest in PTP and will be the operator of the Kitimat LNG terminal. During the fourth quarter of 2010, upon the achievement of certain commercial and regulatory milestones, EOGRC paid $210 million to complete the acquisition of Galveston LNG Inc. In connection with the acquisition, EOG recorded intangible assets related to certain leases, permits and other contracts. Such intangible assets are included in Other Assets on the Consolidated Balance Sheets. During the first quarter of 2011, EOGRC entered into an agreement to purchase an additional 24.5 percent interest in PTP for $24.5 million (subject to customary closing conditions). A portion of the purchase price ($14.7 million) will be paid at closing with the remaining amount ($9.8 million) to be paid contingent on the decision to proceed with the construction of the Kitimat LNG terminal. Subsequent to closing, EOGRC's ownership interest will be 49 percent. An affiliate of Apache Corporation entered into an agreement to purchase the remaining 25.5 percent interest in PTP, which will increase its ownership interest to 51 percent of the proposed project.

As previously reported, EOG began marketing its Canadian shallow natural gas assets in July 2010. In the fourth quarter of 2010, EOG closed on transactions with three separate parties to sell these assets for approximately $344 million, including an estimate of customary adjustments under each respective sales agreement. EOG recorded a pretax impairment of $280 million to adjust the shallow natural gas assets sold to estimated fair value less estimated cost to sell. These assets represented approximately 4% of EOG's total 2009 production and approximately 3% of EOG's total year-end 2009 proved reserves. In addition, EOG received proceeds of approximately $329 million from the sale in 2010 of non-core producing properties and acreage, primarily in the Rocky Mountain area, Texas and Pennsylvania.

International. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium (SECC) Block, Modified U(a) Block and Modified U(b) Block, as well as the Pelican Field, have been developed and are producing. In the Pelican Field, EOG drilled a successful exploratory well that began producing in the first quarter of 2010. In Block 4(a), EOG completed installation of offshore facilities and began its development drilling program in December 2010 to supply natural gas under a contract with the National Gas Company of Trinidad and Tobago (NGC) into the North Eastern Offshore (NEO) pipeline being installed by NGC. EOG is sourcing the natural gas for this contract from its existing fields until the NEO pipeline is completed. Sales under the contract commenced on January 1, 2010.

In the United Kingdom (U.K.), EOG has ongoing production from the Valkyrie field in the Southern Gas Basin of the North Sea Block 49/16f. The last well in the Arthur field ceased production in 2010.

In 2006, EOG Resources United Kingdom Limited (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 expects to submit 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 by the end of 2011. The operator and partners are currently negotiating processing and transportation terms with export infrastructure owners.

In 2009, EOGUK drilled a successful exploratory well in its East Irish Sea blocks. 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 2010, feasibility and front-end engineering design studies were completed, and all principal contracts are currently being negotiated for the development plan. A field development plan for the Conwy field was submitted to the DECC in the first quarter of 2011 and a separate plan is expected to be submitted for the Corfe field before the end of the first quarter of 2011. Regulatory approval of both plans is expected by the end of 2011. Installation of pipelines, drilling of development wells and initial production are planned for 2012. Two additional exploratory wells offsetting the Conwy field were drilled in the first quarter of 2010. Both wells were unsuccessful. The licenses for the East Irish Sea blocks were awarded to EOGUK in 2007.

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 2010, EOG drilled four horizontal wells, one of which was completed in 2010 and another which was completed in January 2011. In addition, EOG completed a horizontal well that was originally drilled in 2009. The wells completed in 2010 began production in the first and second quarters of 2010. EOG plans to complete two wells during the second quarter of 2011. EOG expects to complete its evaluation of the economic viability of this project during the first half of 2011.

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

Capital Structure

One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. EOG's debt-to-total capitalization ratio was 34% and 22% at December 31, 2010 and 2009, respectively. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

During 2010, EOG funded $6.0 billion in exploration and development and other property, plant and equipment expenditures (excluding asset retirement costs and non-cash acquisition costs), paid $153 million in dividends to common stockholders and purchased $11 million of treasury stock in connection with stock compensation plans, primarily by utilizing cash provided from its operating activities, proceeds from long-term debt borrowings described below and proceeds of $673 million from the sale of certain North American assets.

On November 23, 2010, EOG completed its public offering of $400 million aggregate principal amount of 2.500% Senior Notes due 2016 (2016 Notes), $750 million aggregate principal amount of 4.100% Senior Notes due 2021 (2021 Notes) (together, the Fixed Rate Notes) and $350 million aggregate principal amount of Floating Rate Senior Notes due 2014 (the Floating Rate Notes). Interest on the Fixed Rate Notes is payable semiannually in arrears on February 1 and August 1 of each year, beginning on February 1, 2011. Interest on the Floating Rate Notes is payable quarterly in arrears on February 3, May 3, August 3 and November 3 of each year, beginning on February 3, 2011 and is based on the three-month London InterBank Offering Rate (LIBOR) plus 0.75% per annum. The interest rate on the Floating Rate Notes resets quarterly on the interest payment dates. Net proceeds from the offering of approximately $1,487 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings. Contemporaneously with the offering of the Floating Rate Notes, EOG entered into an interest rate swap to fix the interest rate on the Floating Rate Notes at 1.87%.

On September 10, 2010, EOG entered into a second $1.0 billion unsecured Revolving Credit Agreement with domestic and foreign lenders (2010 Agreement). The 2010 Agreement matures on September 10, 2013 (subject to EOG's option to extend, on up to two occasions, the term for successive one-year periods). See Note 2 to Consolidated Financial Statements.

On May 20, 2010, EOG completed its public offering of $500 million aggregate principal amount of 2.95% Senior Notes due 2015 and $500 million aggregate principal amount of 4.40% Senior Notes due 2020 (together, Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning on December 1, 2010. Net proceeds from the offering of approximately $990 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings.

The total anticipated 2011 capital expenditures are $6.4 to $6.6 billion, excluding acquisitions. The majority of 2011 expenditures will be focused on United States and Canada crude oil drilling activity and, to a lesser extent, natural gas drilling activity in the Haynesville, Marcellus and British Columbia Horn River Basin plays to hold acreage. EOG expects capital expenditures to be greater than cash flow from operating activities for 2011. EOG's business plan includes selling certain non-core natural gas assets in 2011 to partially cover the anticipated shortfall. However, EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under its revolving credit facilities and equity and debt offerings.

When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2010 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page F-1.

Net Operating Revenues

During 2010, net operating revenues increased $1,313 million, or 27%, to $6,100 million from $4,787 million in 2009. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, natural gas liquids and natural gas, in 2010 increased $1,482 million, or 44%, to $4,881 million from $3,399 million in 2009. During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million compared to net gains of $432 million in 2009. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party crude oil and condensate, natural gas liquids and natural gas as well as gathering fees associated with gathering third-party natural gas, in 2010 increased $503 million, or 123%, to $910 million from $407 million in 2009. Gains on property dispositions, net, of $224 million in 2010 primarily consist of gains on property dispositions in the Rocky Mountain area. Gains on property dispositions, net, in 2009 primarily consist of a pretax gain of $390 million realized on an exchange of properties in the Rocky Mountain area and a pretax gain of $146 million realized on the sale of EOG's California assets.

Wellhead volume and price statistics for the years ended December 31, 2010, 2009 and 2008 were as follows:

Year Ended December 31	2010	2009	2008
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	63.2	47.9	39.5
Canada	6.7	4.1	2.7
Trinidad	4.7	3.1	3.2
Other International (2)	0.1	0.1	0.1
Total	74.7	55.2	45.5
Average Crude Oil and Condensate Prices ($/Bbl) (3)			
United States	$ 74.88	$ 54.42	$ 87.68
Canada	72.66	57.72	89.70
Trinidad	68.80	50.85	92.90
Other International (2)	73.11	53.07	99.30
Composite	74.29	54.46	88.18
Natural Gas Liquids Volumes (MBbld) (1)			
United States	29.5	22.5	15.0
Canada	0.9	1.1	1.0
Total	30.4	23.6	16.0
Average Natural Gas Liquids Prices ($/Bbl) (3)			
United States	$ 41.68	$ 30.03	$ 53.33
Canada	43.40	30.49	54.77
Composite	41.73	30.05	53.42
Natural Gas Volumes (MMcfd) (1)			
United States	1,133	1,134	1,162
Canada	200	224	222
Trinidad	341	273	218
Other International (2)	14	14	17
Total	1,688	1,645	1,619
Average Natural Gas Prices ($/Mcf) (3)			
United States	$ 4.30	$ 3.72	$ 8.22
Canada	3.91	3.85	7.64
Trinidad	2.65	1.73	3.58
Other International (2)	4.90	4.34	8.18
Composite	3.93	3.42	7.51
Crude Oil Equivalent Volumes (MBoed) (4)			
United States	281.5	259.4	248.4
Canada	40.9	42.6	40.6
Trinidad	61.5	48.5	39.5
Other International (2)	2.5	2.4	2.8
Total	386.4	352.9	331.3
Total MMBoe (4)	141.1	128.8	121.3

(1) Thousand barrels per day or million cubic feet per day, as applicable.
(2) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(3) 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).
(4) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, natural gas liquids and natural gas. Crude oil equivalents are determined using the ratio of 1.0 barrel of crude oil and condensate or natural gas liquids to 6.0 thousand cubic feet of natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

2010 compared to 2009. Wellhead crude oil and condensate revenues in 2010 increased $909 million, or 83%, to $1,999 million from $1,090 million in 2009, due to a higher composite average wellhead crude oil and condensate price ($533 million) and an increase of 20 MBbld, or 35%, in wellhead crude oil and condensate deliveries ($376 million). The increase in deliveries primarily reflects increased production in Texas (8 MBbld), North Dakota (7 MBbld), Canada (3 MBbld) and Trinidad (2 MBbld). Production increases in Texas were the result of increased production from the Fort Worth Basin Barnett Combo and the Eagle Ford plays. Production increases in North Dakota resulted from increased deliveries from the Bakken and Three Forks plays. EOG's composite average wellhead crude oil and condensate price for 2010 increased 36% to $74.29 per barrel compared to $54.46 per barrel in 2009.

Natural gas liquids revenues in 2010 increased $203 million, or 79%, to $462 million from $259 million in 2009, due to a higher composite average price ($129 million) and an increase of 7 MBbld, or 29%, in natural gas liquids deliveries ($74 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area. EOG's composite average natural gas liquids price in 2010 increased 39% to $41.73 per barrel compared to $30.05 per barrel in 2009.

Wellhead natural gas revenues in 2010 increased $369 million, or 18%, to $2,420 million from $2,051 million in 2009. The increase was due to a higher composite average wellhead natural gas price ($316 million) and increased natural gas deliveries ($53 million). EOG's composite average wellhead natural gas price increased 15% to $3.93 per thousand cubic feet (Mcf) in 2010 from $3.42 per Mcf in 2009.

Natural gas deliveries in 2010 increased 43 million cubic feet per day (MMcfd), or 3%, to 1,688 MMcfd from 1,645 MMcfd in 2009. The increase was primarily due to higher production in Trinidad (68 MMcfd), partially offset by decreased production in Canada (24 MMcfd) and the United States (1 MMcfd). The increase in Trinidad was primarily attributable to deliveries under a take-or-pay contract, which began January 1, 2010. The decrease in the United States was primarily attributable to decreased production in the Rocky Mountain area (28 MMcfd), offshore Gulf of Mexico (9 MMcfd), New Mexico (6 MMcfd), Texas (5 MMcfd), Kansas (5 MMcfd) and Mississippi (4 MMcfd), partially offset by increased production in Louisiana (45 MMcfd) and Pennsylvania (11 MMcfd).

During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net realized gains of $7 million. During 2009, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $432 million, which included net realized gains of $1,278 million.

Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, natural gas liquids and natural gas as well as gathering fees associated with gathering third-party natural gas. For the years ended December 31, 2010 and 2009, gathering, processing and marketing revenues were primarily related to sales of third-party crude oil and natural gas. For the year ended December 31, 2008, gathering, processing and marketing revenues were primarily related to sales of third-party natural gas. The purchase and sale of third-party crude oil and natural gas are utilized in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities. Marketing costs represent the costs of purchasing third-party crude oil and natural gas and the associated transportation costs.

During 2010, gathering, processing and marketing revenues and marketing costs increased primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs in 2010 totaled $25 million compared to $10 million in 2009, primarily as a result of higher crude oil marketing margins.

2009 compared to 2008. Wellhead crude oil and condensate revenues decreased $368 million, or 25%, to $1,090 million in 2009 from $1,458 million in 2008, due to a lower composite average wellhead crude oil and condensate price ($675 million), partially offset by an increase of 10 MBbld, or 21%, in wellhead crude oil and condensate deliveries ($307 million). The increase in deliveries primarily reflects increased production in North Dakota (8 MBbld) and Texas (2 MBbld). The composite average wellhead crude oil and condensate price for 2009 decreased 38% to $54.46 per barrel compared to $88.18 per barrel for 2008.

Natural gas liquids revenues decreased $53 million, or 17%, to $259 million in 2009 from $312 million in 2008, due to a lower composite average price ($201 million), partially offset by an increase of 8 MBbld, or 48%, in natural gas liquids deliveries ($148 million). The composite average natural gas liquids price for 2009 decreased 44% to $30.05 per barrel compared to $53.42 per barrel for 2008. The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area.

Wellhead natural gas revenues in 2009 decreased $2,401 million, or 54%, to $2,051 million from $4,452 million for 2008 due to a lower composite average wellhead natural gas price ($2,460 million), partially offset by increased natural gas deliveries ($59 million). EOG's composite average wellhead natural gas price decreased 54% to $3.42 per Mcf in 2009 from $7.51 per Mcf in 2008.

Natural gas deliveries increased 26 MMcfd, or 2%, to 1,645 MMcfd in 2009 from 1,619 MMcfd in 2008. The increase was primarily due to higher production of 55 MMcfd in Trinidad, partially offset by lower production of 28 MMcfd in the United States and 6 MMcfd in the United Kingdom. The increase in Trinidad was primarily due to a reduction in plant shutdowns for maintenance during 2009 (39 MMcfd) and increased net contractual deliveries (16 MMcfd). The decrease in the United States was primarily attributable to decreased production from Texas (26 MMcfd), New Mexico (6 MMcfd), Mississippi (4 MMcfd), Kansas (3 MMcfd) and Oklahoma (3 MMcfd), partially offset by increased production in Louisiana (6 MMcfd) and in the Rocky Mountain area (8 MMcfd). The decrease in production in the United Kingdom was a result of production declines in both the Arthur and Valkyrie fields.

During 2009, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $432 million, which included net realized gains of $1,278 million. During 2008, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $598 million, which included net realized losses of $137 million.

Gathering, processing and marketing revenues less marketing costs decreased $2 million to $10 million in 2009 compared to $12 million in 2008. The decrease resulted primarily from natural gas marketing operations in the Gulf Coast area.

Operating and Other Expenses

2010 compared to 2009. During 2010, operating expenses of $5,577 million were $1,761 million higher than the $3,816 million incurred in 2009. The following table presents the costs per barrel of oil equivalent (Boe) for the years ended December 31, 2010 and 2009:

	2010	2009
Lease and Well	$4.96	$4.50
Transportation Costs	2.74	2.20
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties (1)	13.19	11.29
Other Property, Plant and Equipment	0.79	0.74
General and Administrative (G&A)	1.99	1.93
Net Interest Expense	0.92	0.78
Total (2)	$24.59	$21.44

(1) The 2010 amount excludes the reductions in the estimated fair value of the contingent consideration liability of $24 million, or $0.17 per Boe relating to the acquisition of certain unproved acreage (see Note 12 to Consolidated Financial Statements).

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

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2010 compared to 2009 are set forth below.

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

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

Lease and well expenses of $698 million in 2010 increased $119 million from $579 million in 2009 primarily due to higher operating and maintenance expenses in the United States ($67 million) and Canada ($6 million), increased lease and well administrative expenses in the United States ($27 million), primarily due to higher costs associated with increased crude oil activities, unfavorable changes in the Canadian exchange rate ($14 million) and increased workover expenditures in the United States ($3 million) and Canada ($2 million).

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

Transportation costs of $385 million in 2010 increased $102 million from $283 million in 2009 primarily due to increased transportation costs in the Rocky Mountain area ($46 million), the Upper Gulf Coast area ($29 million) and the Fort Worth Basin Barnett Shale area ($29 million). These increases reflect costs associated with marketing arrangements to transport production to downstream markets. The increased transportation costs in the Rocky Mountain area also include costs associated with EOG's crude-by-rail operations, which began transporting crude oil from Stanley, North Dakota, to Cushing, Oklahoma, at the end of December 2009.

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual field calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles, drilling or acquisition of new wells, disposition of existing wells, reserve revisions (upward or downward) primarily related to well performance and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from year to year. DD&A of the cost of other property, plant and equipment is calculated using the straight-line depreciation method over the useful lives of the assets. Other property, plant and equipment consist of gathering and processing assets, compressors, crude-by-rail assets, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

DD&A expenses in 2010 increased $393 million to $1,942 million from $1,549 million in 2009. DD&A expenses associated with oil and gas properties in 2010 were $378 million higher than in 2009 primarily due to higher unit rates described below and as a result of increased production in the United States ($97 million), Trinidad ($12 million) and China ($2 million), partially offset by a decrease in production in Canada ($8 million). DD&A rates increased due primarily to a proportional increase in production from higher cost properties in the United States ($167 million), Canada ($86 million), Trinidad ($12 million) and China ($8 million) and unfavorable changes in the Canadian exchange rate ($28 million), partially offset by a change in the fair value of the contingent consideration liability ($24 million).

DD&A expenses associated with other property, plant and equipment were $15 million higher in 2010 than in 2009 primarily due to natural gas gathering systems and processing plants being placed in service in the Rocky Mountain area ($10 million) and the Fort Worth Basin Barnett Shale area ($4 million).

G&A expenses of $280 million in 2010 were $32 million higher than 2009 due primarily to higher employee-related costs ($10 million), higher legal and other professional fees ($7 million) and higher information systems costs ($3 million).

Net interest expense of $130 million in 2010 increased $29 million from $101 million in 2009 primarily due to a higher average debt balance ($50 million), partially offset by higher capitalized interest ($21 million).

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

Gathering and processing costs increased $9 million to $67 million in 2010 compared to $58 million in 2009. The increase reflects increased activities in the Fort Worth Basin Barnett Shale area ($6 million) and the Rocky Mountain area ($3 million).

Exploration costs of $187 million in 2010 increased $17 million from $170 million for the same prior year period primarily due to increased employee-related costs in the United States.

Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties. Unproved properties with individually significant acquisition costs are amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. For certain natural gas assets held for sale, EOG utilized accepted bids as the basis for determining fair value.

Impairments of $743 million in 2010 increased $437 million from $306 million in 2009 primarily due to increased impairments of proved properties and other property, plant and equipment in Canada. EOG recorded impairments of proved properties and other property, plant and equipment of $526 million and $94 million in 2010 and 2009, respectively. In 2010, EOG recorded a pretax impairment of $280 million to adjust certain Canadian shallow natural gas assets sold to estimated fair value less estimated cost to sell (see Note 17 to Consolidated Financial Statements). Additionally, EOG recorded pretax impairments of $170 million in the fourth quarter of 2010 related to certain North American onshore and offshore natural gas assets.

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

Taxes other than income in 2010 increased $143 million to $317 million (6.5% of wellhead revenues) from $174 million (5.1% of wellhead revenues) in 2009. The increase in taxes other than income was primarily due to increased severance/production taxes primarily as a result of increased wellhead revenues in the United States ($56 million), Trinidad ($22 million) and Canada ($6 million); a decrease in credits available to EOG in 2010 for Texas high cost gas severance tax rate reductions as a result of fewer wells qualifying for such credit ($43 million); and higher ad valorem/property taxes in the United States ($14 million).

Other income, net was $14 million in 2010 compared to $2 million in 2009. The increase of $12 million was primarily due to higher equity income from ammonia plants in Trinidad ($9 million).

Income tax provision of $247 million in 2010 decreased $78 million compared to 2009 due primarily to decreased pretax income. The net effective tax rate for 2010 increased to 61% from 37% in 2009. The increase in the 2010 net effective tax rate is primarily due to higher state income taxes and to the tax effects of increased earnings in Trinidad and Canadian book losses, which resulted largely from the impairment of certain Canadian shallow natural gas impairments. The statutory tax rates in the United States and Trinidad are higher than the Canadian statutory rate.

2009 compared to 2008. During 2009, operating expenses of $3,816 million were $456 million higher than the $3,360 million incurred in 2008. The following table presents the costs per Boe for the years ended December 31, 2009 and 2008:

	2009	2008
Lease and Well	$4.50	$4.62
Transportation Costs	2.20	2.26
DD&A -		
Oil and Gas Properties	11.29	10.41
Other Property, Plant and Equipment	0.74	0.54
G&A	1.93	2.01
Net Interest Expense	0.78	0.43
Total (1)	$21.44	$20.27

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

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2009 compared to 2008 are set forth below.

Lease and well expenses of $579 million in 2009 increased $20 million from $559 million in 2008 due primarily to higher operating and maintenance expenses in Canada ($16 million) and the United States ($14 million), partially offset by changes in the Canadian exchange rate ($8 million) and lower lease and well administrative expenses ($5 million).

Transportation costs of $283 million in 2009 increased $9 million from $274 million in 2008 primarily due to increased transportation costs in the Rocky Mountain area ($19 million), partially offset by decreased transportation costs in the Fort Worth Basin Barnett Shale area ($8 million).

DD&A expenses in 2009 increased $222 million to $1,549 million from $1,327 million in 2008. DD&A expenses associated with oil and gas properties were $192 million higher than in 2008 primarily due to higher unit rates described below and as a result of increased production in the United States ($42 million), Canada ($9 million) and Trinidad ($6 million), partially offset by a decrease in production in the United Kingdom ($3 million). DD&A rates increased due primarily to a proportional increase in production from higher cost properties in the United States ($105 million), Canada ($22 million) and Trinidad ($13 million), partially offset by changes in the Canadian exchange rate ($13 million).

DD&A expenses associated with other property, plant and equipment were $30 million higher in 2009 than in 2008 primarily due to increased expenditures associated with gathering and processing assets in the Fort Worth Basin Barnett Shale area ($16 million) and the Rocky Mountain area ($9 million).

G&A expenses of $248 million in 2009 were $5 million higher than 2008 due primarily to higher insurance costs ($3 million) and higher employee-related costs ($2 million).

Net interest expense of $101 million in 2009 increased $49 million from $52 million in 2008 primarily due to a higher average debt balance ($61 million), partially offset by higher capitalized interest ($12 million).

Gathering and processing costs increased $17 million to $58 million in 2009 compared to $41 million in 2008. The increase primarily reflects increased activities in the Fort Worth Basin Barnett Shale area ($8 million) and the Rocky Mountain area ($8 million).

Exploration costs of $170 million in 2009 decreased $24 million from $194 million for the same prior year period primarily due to decreased geological and geophysical expenditures in the Fort Worth Basin Barnett Shale area.

Impairments of $306 million in 2009 increased $113 million from $193 million in 2008 primarily due to increased amortization of unproved property costs in the United States ($103 million) and increased impairments of proved properties in the United States ($32 million), partially offset by 2008 impairments in Trinidad as a result of EOG's relinquishment of its rights to Block Lower Reverse "L" (LRL) ($20 million) and in the U.K. for the Arthur field ($6 million). EOG recorded impairments of proved properties of $94 million and $86 million for 2009 and 2008, respectively.

Taxes other than income in 2009 decreased $147 million to $174 million (5.1% of wellhead revenues) from $321 million (5.2% of wellhead revenues) in 2008. The decrease in taxes other than income was primarily due to decreased severance/production taxes primarily as a result of decreased wellhead revenues in the United States ($103 million), Trinidad ($13 million) and Canada ($3 million); an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions ($16 million); and lower ad valorem/property taxes in the United States ($15 million).

Other income, net was $2 million in 2009 compared to $31 million in 2008. The decrease of $29 million was primarily due to lower equity income from ammonia plants in Trinidad ($15 million), lower interest income ($8 million) and settlements received in 2008 related to a bankruptcy ($3 million).

Income tax provision of $325 million in 2009 decreased $984 million compared to 2008 due primarily to decreased pretax income. The net effective tax rate for 2009 increased to 37% from 35% in 2008. The increase in the 2009 net effective tax rate is primarily as a result of higher state tax rates and the absence of 2008 tax benefits related to the impairment of LRL.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2010 were funds generated from operations, net proceeds from issuances of long-term debt, proceeds from the sale of oil and gas properties, proceeds from stock options exercised and employee stock purchase plan activity, net commercial paper borrowings and borrowings under other uncommitted credit facilities and revolving credit facilities. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; dividend payments to stockholders; and repayments of debt.

2010 compared to 2009. Net cash provided by operating activities of $2,709 million in 2010 decreased $213 million from $2,922 million in 2009 primarily reflecting an unfavorable change in the net cash flow from the settlement of financial commodity derivative contracts ($1,271 million), an increase in cash operating expenses ($410 million), an increase in cash paid for income taxes ($182 million), an increase in cash paid for interest expense ($46 million), and unfavorable changes in working capital and other assets and liabilities ($7 million), partially offset by an increase in wellhead revenues ($1,482 million).

Net cash used in investing activities of $4,903 million in 2010 increased by $1,488 million from $3,415 million for the same period of 2009 due primarily to an increase in additions to oil and gas properties ($2,034 million); the acquisition of Galveston LNG Inc. ($210 million); and an increase in additions to other property, plant and equipment ($45 million); partially offset by an increase in proceeds from sales of assets ($461 million); and favorable changes in working capital associated with investing activities ($327 million).

Net cash provided by financing activities of $2,303 million in 2010 included proceeds from the issuances of long-term debt ($2,479 million) and proceeds from stock options exercised and employee stock purchase plan activity ($35 million). Cash used in financing activities during 2010 included cash dividend payments ($153 million), the repayment of long-term debt ($37 million), treasury stock purchases in connection with stock compensation plans ($11 million) and debt issuance costs ($8 million).

2009 compared to 2008. Net cash provided by operating activities of $2,922 million in 2009 decreased $1,711 million from $4,633 million in 2008 primarily reflecting a decrease in wellhead revenues ($2,823 million); unfavorable changes in working capital and other assets and liabilities ($335 million); an increase in cash operating expenses ($125 million); and an increase in cash paid for interest expense ($53 million); partially offset by a favorable change in the net cash flow from the settlement of financial commodity derivative contracts ($1,414 million); an increase in gathering, processing and marketing revenues ($243 million); and a decrease in cash paid for income taxes ($43 million).

Net cash used in investing activities of $3,415 million in 2009 decreased by $1,552 million from $4,967 million for the same period of 2008 due primarily to a decrease in additions to oil and gas properties ($1,542 million); a decrease in additions to other property, plant and equipment ($150 million); and favorable changes in working capital associated with investing activities ($34 million); partially offset by a decrease in proceeds from sales of assets ($172 million). Proceeds from sales of assets included net proceeds from the sale of EOG's California assets in December 2009 ($200 million) and net proceeds from the sale of EOG's Appalachian assets in February 2008 ($386 million).

Net cash provided by financing activities of $834 million in 2009 included the issuance of long-term debt ($900 million), excess tax benefits from stock-based compensation ($76 million) and proceeds from stock options exercised and employee stock purchase plan activity ($20 million). Cash used in financing activities during 2009 included cash dividend payments ($142 million), treasury stock purchases in connection with stock compensation plans ($11 million) and debt issuance costs ($9 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2010, 2009 and 2008 (in millions):

		Actual	
	2010	2009	2008
Expenditure Category			
Capital			
Drilling and Facilities	$4,634	$2,417	$3,990
Leasehold Acquisitions	399	424	521
Property Acquisitions (1)	18	707	109
Capitalized Interest	76	55	43
Subtotal	5,127	3,603	4,663
Exploration Costs	187	170	194
Dry Hole Costs	72	51	55
Exploration and Development Expenditures	5,386	3,824	4,912
Asset Retirement Costs	72	84	181
Total Exploration and Development Expenditures	5,458	3,908	5,093
Other Property, Plant and Equipment (2)	581	326	477
Total Expenditures	$6,039	$4,234	$5,570

(1) In 2009, property acquisitions included non-cash additions of $353 million related to a property exchange transaction in the Rocky Mountain area. In 2009 and 2010, property acquisitions also included non-cash additions for contingent consideration, with estimated fair values of $35 million and $3 million, respectively, related to the acquisition of the Haynesville Assets (see Note 17 to Consolidated Financial Statements).

(2) In 2010, other property, plant and equipment included $210 million for the acquisition of Galveston LNG Inc. (see Note 17 to Consolidated Financial Statements).

Exploration and development expenditures of $5,386 million for 2010 were $1,562 million higher than the prior year due primarily to increased drilling and facilities expenditures in the United States ($1,932 million), Canada ($134 million), Trinidad ($104 million) and China ($15 million); unfavorable changes in the foreign currency exchange rate in Canada ($58 million); increased capitalized interest in the United States ($21 million); increased employee-related exploration costs in the United States ($11 million); and increased dry hole costs in the United Kingdom ($11 million) and Canada ($10 million). These increases were partially offset by decreased property acquisition expenditures in the United States ($689 million), decreased leasehold acquisition expenditures in the United States ($20 million) and decreased dry hole costs in the United States ($9 million). The 2010 exploration and development expenditures of $5,386 million included $4,366 million in development, $926 million in exploration, $76 million in capitalized interest and $18 million in property acquisitions. The increase in expenditures for other property, plant and equipment was primarily due to the acquisition of Galveston LNG Inc. The 2009 exploration and development expenditures of $3,824 million included $2,082 million in development, $980 million in exploration, $707 million in property acquisitions and $55 million in capitalized interest. The decrease in expenditures for other property, plant and equipment primarily related to gathering and processing assets in the Fort Worth Basin Barnett Shale area. The 2008 exploration and development expenditures of $4,912 million included $3,612 million in development, $1,148 million in exploration, $109 million in property acquisitions and $43 million in capitalized interest. The increase in expenditures for other property, plant and equipment primarily related to gathering and processing assets in the Fort Worth Basin Barnett Shale and Rocky Mountain areas.

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

Derivative Transactions

During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net realized gains of $7 million. During 2009, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $432 million, which included net realized gains of $1,278 million. See Note 11 to Consolidated Financial Statements.

Financial Price Swap Contracts. The total fair value of EOG's crude oil and natural gas financial price swap contracts is reflected in the Consolidated Balance Sheets at December 31, 2010 as an asset of $69 million and a liability of $21 million, respectively. Presented below is a comprehensive summary of EOG's crude oil and natural gas financial price swap contracts at February 24, 2011, with notional volumes expressed in barrels per day (Bbld) and in million British thermal units per day (MMBtud) and prices expressed in dollars per barrel ($/Bbl) and in dollars per million British thermal units ($/MMBtu), as applicable.

Financial Price Swap Contracts

	Crude Oil		Natural Gas	
	Volume (Bbld)	Weighted Average Price ($/Bbl)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2011 (1)				
January 2011 (2)	17,000	$ 90.44	275,000	$ 5.19
February 1, 2011 through March 31, 2011 (3)	18,000	90.69	425,000	5.09
April 1, 2011 through December 31, 2011	20,000	91.48	425,000	5.09
2012 (4)				
January 1, 2012 through December 31, 2012	2,000	$ 100.50	250,000	$ 5.56

(1) Natural gas financial price swap contracts include unexercised swaption contracts which give counterparties the option of entering into price swap contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas financial price swap contracts will increase by 275,000 MMBtud at an average price of $4.90 per MMBtu for the period from April 1, 2011 through December 31, 2011.
(2) The crude oil and natural gas contracts for January 2011 are closed.
(3) The crude oil contracts for February 2011 through March 2011 will close February 28, 2011 and March 31, 2011, respectively. The natural gas contracts for February 2011 through March 2011 are closed.
(4) Natural gas financial price swap contracts include unexercised swaption contracts which give counterparties the option of entering into price swap contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas financial price swap contracts will increase by 150,000 MMBtud at an average price of $5.64 per MMBtu for each month of 2012.

Financial Basis Swap Contracts. Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG has entered into natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. The total fair value of EOG's natural gas financial basis swap contracts is reflected in the Consolidated Balance Sheets at December 31, 2010 as a liability of $9 million. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at February 24, 2011. The weighted average price differential represents the amount of reduction to NYMEX gas prices per million British thermal units (MMBtu) for the notional volumes covered by the basis swap.

Natural Gas Financial Basis Swap Contracts

	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)

2011		
First Quarter (closed)	65,000	$(1.89)

Financing

EOG's debt-to-total capitalization ratio was 34% at December 31, 2010 compared to 22% at December 31, 2009. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

During 2010, total debt increased $2,463 million to $5,260 million. The estimated fair value of EOG's debt at December 31, 2010 and 2009 was $5,602 million and $3,056 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, upon interest rates available to EOG at year-end. EOG's debt is primarily at fixed interest rates. At December 31, 2010, a 1% decline in interest rates would result in a $330 million increase in the estimated fair value of the fixed rate obligations. See Note 2 to Consolidated Financial Statements.

During 2010, EOG utilized cash provided by operating activities, proceeds from the issuance of the Fixed Rate Notes, Floating Rate Notes and Notes described below, proceeds from asset sales and cash provided by borrowings from net commercial paper and other uncommitted credit facilities to fund its capital programs. While EOG maintains a $2.0 billion commercial paper program, the maximum outstanding at any time during 2010 was $1,039 million, and the amount outstanding at year-end was zero. The maximum amount outstanding under uncommitted credit facilities during 2010 was $14 million with no amounts outstanding at year-end. The average borrowings outstanding under the commercial paper program and the uncommitted credit facilities were $191 million and $0.1 million, respectively, during the year 2010. EOG considers this excess availability, which is backed by the two $1.0 billion unsecured Revolving Credit Agreements with domestic and foreign lenders described in Note 2 to Consolidated Financial Statements, to be ample to meet its ongoing operating needs.

On November 23, 2010, EOG completed its public offering of $400 million aggregate principal amount of 2.500% Senior Notes due 2016 (2016 Notes), $750 million aggregate principal amount of 4.100% Senior Notes due 2021 (2021 Notes) (together, the Fixed Rate Notes) and $350 million aggregate principal amount of Floating Rate Senior Notes due 2014 (the Floating Rate Notes). Interest on the Fixed Rate Notes is payable semiannually in arrears on February 1 and August 1 of each year, beginning on February 1, 2011. Interest on the Floating Rate Notes is payable quarterly in arrears on February 3, May 3, August 3 and November 3 of each year, beginning on February 3, 2011 and is based on the three-month LIBOR plus 0.75% per annum. The interest rate on the Floating Rate Notes resets quarterly on the interest payment dates. Net proceeds from the offering of approximately $1,487 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings. Contemporaneously with the offering of the Floating Rate Notes, EOG entered into an interest rate swap to fix the interest rate on the Floating Rate Notes at 1.87%.

On May 20, 2010, EOG completed its public offering of $500 million aggregate principal amount of 2.95% Senior Notes due 2015 and $500 million aggregate principal amount of 4.40% Senior Notes due 2020 (together, Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning on December 1, 2010. Net proceeds from the Notes offering of approximately $990 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings.

On May 21, 2009, EOG completed its public offering of $900 million aggregate principal amount of 5.625% Senior Notes due 2019 (2019 Notes). Interest on the 2019 Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning on December 1, 2009. Net proceeds from the offering of approximately $891 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2010 (in thousands):

Contractual Obligations (1)	Total	2011	2012 - 2013	2014 - 2015	2016 & Beyond
Current and Long-Term Debt	$5,260,000	$220,000	$400,000	$1,000,000	$3,640,000
Non-Cancelable Operating Leases	357,049	107,174	60,637	47,562	141,676
Interest Payments on Long-Term Debt	1,808,415	237,367	470,035	391,356	709,657
Pipeline Transportation Service Commitments (2)	3,315,075	305,529	688,817	777,117	1,543,612
Drilling Rig Commitments (3)	355,277	213,442	135,867	5,968	-
Seismic Purchase Obligations	4,050	4,050	-	-	-
Fracturing Services Obligations	367,656	220,858	121,283	25,515	-
Other Purchase Obligations	219,796	218,808	669	319	-
Total Contractual Obligations	$11,687,318	$1,527,228	$1,877,308	$2,247,837	$6,034,945

(1) This table does not include the liability for unrecognized tax benefits, EOG's pension or postretirement benefit obligations or liability for dismantlement, abandonment and asset retirement obligations (see Notes 5, 6 and 14, respectively, to Consolidated Financial Statements).

(2) Amounts shown are based on current pipeline transportation rates and the foreign currency exchange rates used to convert Canadian dollars and British pounds into United States dollars at December 31, 2010. Management does not believe that any future changes in these rates before the expiration dates of these commitments will have a material adverse effect on the financial condition or results of operations of EOG.

(3) Amounts shown represent minimum future expenditures for drilling rig services. EOG's expenditures for drilling rig services will exceed such minimum amounts to the extent EOG utilizes the drilling rigs subject to a particular contractual commitment for a period greater than the period set forth in the governing contract or if EOG utilizes drilling rigs in addition to the drilling rigs subject to the particular contractual commitment (for example, pursuant to the exercise of an option to utilize additional drilling rigs provided for in the governing contract).

Off-Balance Sheet Arrangements

EOG does not participate in financial transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities or partnerships, often referred to as variable interest entities (VIE) or special purpose entities (SPE), are generally established for the purpose of facilitating off-balance sheet arrangements or other limited purposes. EOG was not involved in any unconsolidated VIE or SPE financial transactions or any other "off-balance sheet arrangement" (as defined in Item 303(a)(4)(ii) of Regulation S-K) during any of the periods covered by this report, and currently has no intention of participating in any such transaction or arrangement in the foreseeable future.

Foreign Currency Exchange Rate Risk

During 2010, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Canada, Trinidad, the U.K. and China. The foreign currency most significant to EOG's operations during 2010 was the Canadian dollar. The fluctuation of the Canadian dollar in 2010 impacted both the revenues and expenses of EOG's Canadian subsidiaries. However, since Canadian commodity prices are largely correlated to United States prices, the changes in the Canadian currency exchange rate have less of an impact on the Canadian revenues than the Canadian expenses. EOG continues to monitor the foreign currency exchange rates of countries in which it is currently conducting business and may implement measures to protect against the foreign currency exchange rate risk.

Effective March 9, 2004, EOG entered into a foreign currency swap transaction with multiple banks to eliminate exchange rate impacts that may result from the notes offered by one of its Canadian subsidiaries on the same date (see Note 2 to Consolidated Financial Statements). EOG accounts for the foreign currency swap transaction using the hedge accounting method, pursuant to the provisions of the Derivatives and Hedging Topic of the Financial Accounting Standards Board's Accounting Standards Codification (ASC). Under those provisions, as of December 31, 2010, EOG recorded the fair value of the foreign currency swap of $55 million in Other Liabilities on the Consolidated Balance Sheets. Changes in the fair value of the foreign currency swap resulted in no net impact to Net Income Available to Common Stockholders on the Consolidated Statements of Income and Comprehensive Income. The after-tax net impact from the foreign currency swap transaction resulted in a positive change of $3 million for the year ended December 31, 2010. The change is included in Accumulated Other Comprehensive Income in the Stockholders' Equity section of the Consolidated Balance Sheets.

Outlook

Pricing. Crude oil and natural gas prices have been volatile and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, the availabilities of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, EOG is unable to predict what changes may occur in crude oil and condensate, natural gas liquids, natural gas, ammonia and methanol prices in the future. The market price of crude oil and condensate, natural gas liquids and natural gas in 2011 will impact the amount of cash generated from operating activities, which will in turn impact EOG's financial position.

Including the impact of EOG's 2011 crude oil hedges and based on EOG's tax position, EOG's price sensitivity in 2011 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 $26 million for net income and $38 million for cash flows from operating activities. Including the impact of EOG's 2011 natural gas hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2011 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 $19 million for net income and $28 million for cash flows from operating activities. For information regarding EOG's crude oil and natural gas hedge position as of December 31, 2010, see Note 11 to Consolidated Financial Statements.

Capital. EOG plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in the United States and Canada. In particular, EOG will be focused on United States and Canada crude oil drilling activity in its Eagle Ford, Bakken and Three Forks and Barnett Combo plays and, to a lesser extent, natural gas drilling activity in the Haynesville, Marcellus and British Columbia Horn River Basin plays. In order to diversify its overall asset portfolio, EOG expects to conduct exploratory activity in other areas outside of the United States and Canada and will continue to evaluate the potential for involvement in additional exploitation-type opportunities.

The total anticipated 2011 capital expenditures of $6.4 to $6.6 billion, excluding acquisitions, is structured to maintain the flexibility necessary under EOG's strategy of funding its exploration, development, exploitation and acquisition activities primarily from available internally generated cash flow and the sale of certain non-core natural gas assets. However, EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under its revolving credit facilities and equity and debt offerings.

Operations. EOG expects to increase overall production in 2011 by 9.5% over 2010 levels. Total liquids production is expected to increase by 49%, comprised of an increase in crude oil and condensate and natural gas liquids production of 55% and 34%, respectively. North American natural gas production is expected to decrease by 5% from 2010 levels.

Summary of Critical Accounting Policies

EOG prepares its financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States of America, which requires management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. EOG identifies certain accounting policies as critical based on, among other things, their impact on the portrayal of EOG's financial condition, results of operations or liquidity, and the degree of difficulty, subjectivity and complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Following is a discussion of EOG's most critical accounting policies:

Proved Oil and Gas Reserves

EOG's engineers estimate proved oil and gas reserves, which directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of crude oil and condensate, natural gas liquids and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. 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. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. For related discussion, see ITEM 1A. Risk Factors.

Oil and Gas Exploration Costs

EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting. Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered proved commercial reserves. Exploratory drilling costs are capitalized when drilling is complete if it is determined that there is economic producibility supported by either actual production, a conclusive formation test or by certain technical data if the discovery is located offshore. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. As of December 31, 2010 and 2009, EOG had exploratory drilling costs related to projects that have been deferred for more than one year (see Note 16 to Consolidated Financial Statements). These costs meet the accounting requirements outlined above for continued capitalization. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease, respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account. Certain other assets, including natural gas gathering and processing facilities, are depreciated on a straight-line basis over the estimated useful life of the asset.

Assets are grouped in accordance with the provisions of the Extractive Industries - Oil and Gas Topic of the ASC. The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions and/or property dispositions and impairments.

Impairments

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

Stock-Based Compensation

In accounting for stock-based compensation, judgments and estimates are made regarding, among other things, the appropriate valuation methodology to follow in valuing stock compensation awards and the related inputs required by those valuation methodologies. Assumptions regarding expected volatility of EOG's common stock, the level of risk-free interest rates, expected dividend yields on EOG's stock, the expected term of the awards and other valuation inputs are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized in the Consolidated Statements of Income and Comprehensive Income.

Information Regarding Forward-Looking Statements

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

- the timing and extent of changes in prices for, and demand for, crude oil, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;

- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling and advanced completion technologies;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, and to produce reserves and achieve anticipated production levels from, its existing and future crude oil and natural gas exploration and development projects, given the risks and uncertainties inherent in drilling, completing and operating crude oil and natural gas wells and the potential for interruptions of development and production, whether involuntary or intentional as a result of market or other conditions;

- the extent to which EOG is successful in its efforts to market its crude oil, natural gas and related commodity production;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal and hydraulic fracturing and laws and regulations imposing conditions and restrictions on drilling and completion operations;
- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- competition in the oil and gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation of production, gathering, processing, compression and transportation facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- political developments around the world, including in the areas in which EOG operates;
- the timing and impact of liquefied natural gas imports;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors", on pages 14 through 20 of this Annual Report on Form 10-K and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

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

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by this Item is incorporated by reference from Item 7 of this report, specifically the information set forth under the captions "Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

ITEM 8. Financial Statements and Supplementary Data

The information required by this Item is included in this report as set forth in the "Index to Financial Statements" on page F-1 and is incorporated by reference herein.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures. EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of December 31, 2010. Based on this evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of December 31, 2010 in ensuring that information that is required to be disclosed by EOG in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms and (ii) accumulated and communicated to EOG's management as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. EOG's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2010. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control - Integrated Framework. Based on this assessment and such criteria, EOG's management believes that EOG's internal control over financial reporting was effective as of December 31, 2010. See also "Management's Responsibility for Financial Reporting" appearing on page F-2 of this report, which is incorporated herein by reference.

The report of EOG's independent registered public accounting firm relating to the consolidated financial statements, financial statement schedules and effectiveness of internal control over financial reporting is set forth beginning on page F-3 of this report.

There were no changes in EOG's internal control over financial reporting that occurred during the quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information required by this Item is incorporated by reference from (i) EOG's Definitive Proxy Statement with respect to its 2011 Annual Meeting of Stockholders to be filed not later than April 30, 2011 and (ii) Item 1 of this report, specifically the information therein set forth under the caption "Executive Officers of the Registrant."

Pursuant to Rule 303A.10 of the New York Stock Exchange and Item 406 of Regulation S-K promulgated under the Securities Exchange Act of 1934, as amended, EOG has adopted a Code of Business Conduct and Ethics (Code of Conduct) that applies to all EOG directors, officers and employees, including EOG's principal executive officer, principal financial officer and principal accounting officer. EOG has also adopted a Code of Ethics for Senior Financial Officers (Code of Ethics) that, along with EOG's Code of Conduct, applies to EOG's principal executive officer, principal financial officer, principal accounting officer and controllers.

You can access the Code of Conduct and Code of Ethics on the Corporate Governance page under Investors on EOG's website at www.eogresources.com, and any EOG stockholder who so requests may obtain a printed copy of the Code of Conduct and Code of Ethics by submitting a written request to EOG's Corporate Secretary.

EOG intends to disclose any amendments to the Code of Conduct or Code of Ethics, and any waivers with respect to the Code of Conduct or Code of Ethics granted to EOG's principal executive officer, principal financial officer, principal accounting officer, any of our controllers or any of our other employees performing similar functions, on its website at www.eogresources.com within four business days of the amendment or waiver. In such case, the disclosure regarding the amendment or waiver will remain available on EOG's website for at least 12 months after the initial disclosure. There have been no waivers granted with respect to EOG's Code of Conduct or Code of Ethics.

ITEM 11. Executive Compensation

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2011 Annual Meeting of Stockholders to be filed not later than April 30, 2011. The Compensation Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically incorporates such information by reference into such a filing.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item with respect to security ownership of certain beneficial owners and management is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2011 Annual Meeting of Stockholders to be filed not later than April 30, 2011.

Equity Compensation Plan Information

Stock Plans Approved by EOG Stockholders. EOG's stockholders approved the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) at the 2008 Annual Meeting of Stockholders in May 2008. At the 2010 Annual Meeting of Stockholders in April 2010 (2010 Annual Meeting), an amendment to the 2008 Plan was approved, pursuant to which the number of shares of common stock available for future grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards under the 2008 Plan was increased by an additional 6.9 million shares, to an aggregate maximum of 12.9 million shares plus shares underlying forfeited or cancelled grants under the prior stock plans referenced below. Under the 2008 Plan, grants may be made to employees and non-employee members of EOG's Board of Directors (Board).

At the 2010 Annual Meeting, an amendment to the Employee Stock Purchase Plan (ESPP) was approved to increase the shares available for grant by 1.0 million shares. The ESPP was originally approved by EOG's stockholders in 2001, and would have expired on July 1, 2011. The amendment also extended the term of the ESPP to December 31, 2019, unless terminated earlier by its terms or by EOG.

The 1992 Stock Plan and the 1993 Nonemployee Directors Stock Option Plan have also been approved by EOG's stockholders. Plans that have not been approved by EOG's stockholders are described below.

Stock Plans Not Approved by EOG Stockholders. The Board approved the 1994 Stock Plan, which provides equity compensation to employees who are not officers within the meaning of Rule 16a-1 of the Securities Exchange Act of 1934, as amended. Under the 1994 Stock Plan, employees have been granted stock options (rights to purchase shares of EOG common stock at a price not less than the market price of the stock on the date of grant). These stock options vest on a graded vesting schedule up to four years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Terms for stock options granted under the 1994 Stock Plan have not exceeded a maximum term of 10 years. Employees have also been granted shares of restricted stock and/or restricted stock units under the 1994 Stock Plan without cost to the employee. The shares and units granted vest up to five years after the date of grant as defined in individual grant agreements. Shares of restricted stock, upon vesting, are released to the employee. Each restricted stock unit, upon vesting, is converted into one share of EOG common stock and released to the employee. Upon the effective date of the 2008 Plan, no further grants were made under the 1994 Stock Plan.

In December 2008, the Board approved the amendment and continuation of the 1996 Deferral Plan as the "EOG Resources, Inc. 409A Deferred Compensation Plan" (Deferral Plan). Under the Deferral Plan, payment of up to 50% of base salary, 100% of annual cash bonus, directors fees and 401(k) refunds resulting from excess deferrals in the EOG Resources, Inc. Savings Plan may be deferred into a phantom stock account. In the phantom stock account, deferrals are treated as if shares of EOG common stock were purchased at the closing stock price on the date of deferral. Dividends are credited quarterly and treated as if reinvested in EOG common stock. Payment of the phantom stock account is made in actual shares of EOG common stock in accordance with the Deferral Plan and the individual's deferral election. A total of 120,000 shares have been registered for issuance under the Deferral Plan. As of December 31, 2010, 111,333 phantom shares had been issued.

The following table sets forth data for EOG's equity compensation plans aggregated by the various plans approved by EOG's stockholders and those plans not approved by EOG's stockholders as of December 31, 2010.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))	
Equity Compensation Plans Approved by EOG Stockholders	11,403,618	$ 73.54	7,978,337	(1) (2)
Equity Compensation Plans Not Approved by EOG Stockholders	1,128,550	$ 23.37	8,667	(3)
Total	12,532,168	$ 69.03	7,987,004	

(1) Of these securities, 924,274 shares remain available for purchase under the Employee Stock Purchase Plan.
(2) Of these securities, 2,303,186 could be issued as restricted stock or restricted stock units under the 2008 Plan.
(3) Represents 8,667 shares that remain available for issuance under the Deferral Plan (as described above).

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2011 Annual Meeting of Stockholders to be filed not later than April 30, 2011.

ITEM 14. Principal Accounting Fees and Services

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2011 Annual Meeting of Stockholders to be filed not later than April 30, 2011.

PART IV

ITEM 15. Exhibits, Financial Statement Schedules

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedule

See "Index to Financial Statements" set forth on page F-1.

(a)(3), (b) Exhibits

See pages E-1 through E-7 for a listing of the exhibits.

EOG RESOURCES, INC.
INDEX TO FINANCIAL STATEMENTS

Other financial statement schedules have been omitted because they are inapplicable or the information required therein is included elsewhere in the consolidated financial statements or notes thereto.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The following consolidated financial statements of EOG Resources, Inc., together with its subsidiaries (collectively, EOG), were prepared by management, which is responsible for the integrity, objectivity and fair presentation of such financial statements. The statements have been prepared in conformity with generally accepted accounting principles in the United States of America and, accordingly, include some amounts that are based on the best estimates and judgments of management.

EOG's management is also responsible for establishing and maintaining adequate internal control over financial reporting. The system of internal control of EOG is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America. This system consists of 1) entity level controls, including written policies and guidelines relating to the ethical conduct of business affairs, 2) general computer controls and 3) process controls over initiating, authorizing, recording, processing and reporting transactions. Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

The adequacy of EOG's financial controls and the accounting principles employed by EOG in its financial reporting are under the general oversight of the Audit Committee of the Board of Directors. No member of this committee is an officer or employee of EOG. Moreover, EOG's independent registered public accounting firm and internal auditors have full, free, separate and direct access to the Audit Committee and meet with the committee periodically to discuss accounting, auditing and financial reporting matters.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2010. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control - Integrated Framework. These criteria cover the control environment, risk assessment process, control activities, information and communication systems, and monitoring activities. Based on this assessment and those criteria, management believes that EOG maintained effective internal control over financial reporting as of December 31, 2010.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements of EOG and to issue a report thereon. In the conduct of the audit, Deloitte & Touche LLP was given unrestricted access to all financial records and related data, including minutes of all meetings of stockholders, the Board of Directors and committees of the Board. Management believes that all representations made to Deloitte & Touche LLP during the audit were valid and appropriate. Their audit was made in accordance with standards of the Public Company Accounting Oversight Board (United States) and included a review of EOG's system of internal controls to the extent considered necessary to determine the audit procedures required to support their opinion on EOG's consolidated financial statements and the effectiveness of EOG's internal control over financial reporting. Their report begins on page F-3.

MARK G. PAPA	TIMOTHY K. DRIGGERS
Chairman of the Board and	Vice President and Chief
Chief Executive Officer	Financial Officer

Houston, Texas
February 24, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
EOG Resources, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of EOG Resources, Inc. and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EOG Resources, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009, the Company adopted the updated oil and gas reserve estimation and disclosure rules.

DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2011

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(In Thousands, Except Per Share Data)

Year Ended December 31	2010	2009	2008
Net Operating Revenues			
Crude Oil and Condensate	$1,998,771	$1,089,711	$1,457,623
Natural Gas Liquids	462,345	258,799	312,303
Natural Gas	2,420,099	2,050,963	4,452,058
Gains on Mark-to-Market Commodity Derivative Contracts	61,912	431,757	597,911
Gathering, Processing and Marketing	909,680	407,116	164,535
Gains on Property Dispositions, Net	223,538	535,436	123,473
Other, Net	23,551	13,177	19,240
Total	6,099,896	4,786,959	7,127,143
Operating Expenses			
Lease and Well	698,430	579,290	559,185
Transportation Costs	385,189	283,329	274,090
Gathering and Processing Costs	66,758	57,632	40,550
Exploration Costs	187,381	169,592	193,886
Dry Hole Costs	72,486	51,243	55,167
Impairments	742,647	305,832	192,859
Marketing Costs	884,212	397,375	152,842
Depreciation, Depletion and Amortization	1,941,926	1,549,188	1,326,875
General and Administrative	280,474	248,274	243,708
Taxes Other Than Income	317,074	174,363	320,796
Total	5,576,577	3,816,118	3,359,958
Operating Income	523,319	970,841	3,767,185
Other Income, Net	14,243	2,071	31,012
Income Before Interest Expense and Income Taxes	537,562	972,912	3,798,197
Interest Expense			
Incurred	205,886	155,820	94,286
Capitalized	(76,300)	(54,919)	(42,628)
Net Interest Expense	129,586	100,901	51,658
Income Before Income Taxes	407,976	872,011	3,746,539
Income Tax Provision	247,322	325,384	1,309,620
Net Income	160,654	546,627	2,436,919
Preferred Stock Dividends	-	-	443
Net Income Available to Common Stockholders	$160,654	$546,627	$2,436,476
Net Income Per Share Available to Common Stockholders			
Basic	$0.64	$2.20	$9.88
Diluted	$0.63	$2.17	$9.72
Dividends Declared per Common Share	$0.62	$0.58	$0.51
Average Number of Common Shares			
Basic	250,876	248,996	246,662
Diluted	254,500	251,884	250,542
Comprehensive Income			
Net Income	$160,654	$546,627	$2,436,919

Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	96,179	308,286	(431,940)
Foreign Currency Swap Transaction	4,447	6,336	(9,637)
Income Tax Related to Foreign Currency Swap Transaction	(1,203)	(1,519)	2,442
Defined Benefit Pension and Postretirement Plans	(258)	(1,469)	608
Income Tax Related to Defined Benefit Pension and Postretirement Plans	7	299	(388)
Interest Rate Swap Transaction	1,843	-	-
Income Tax Related to Interest Rate Swap Transaction	(664)	-	-
Comprehensive Income	$261,005	$858,560	$1,998,004

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

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

At December 31	2010	2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$788,853	$685,751
Accounts Receivable, Net	1,113,279	771,417
Inventories	415,792	261,723
Assets from Price Risk Management Activities	48,153	20,915
Income Taxes Receivable	54,916	37,009
Deferred Income Taxes	9,260	-
Other	97,193	62,726
Total	2,527,446	1,839,541
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	29,263,809	24,614,311
Other Property, Plant and Equipment	1,733,073	1,350,132
Total Property, Plant and Equipment	30,996,882	25,964,443
Less: Accumulated Depreciation, Depletion and Amortization	(12,315,982)	(9,825,218)
Total Property, Plant and Equipment, Net	18,680,900	16,139,225
Other Assets	415,887	139,901
Total Assets	$21,624,233	$18,118,667
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$1,664,944	$979,139
Accrued Taxes Payable	82,168	92,858
Dividends Payable	38,962	36,286
Liabilities from Price Risk Management Activities	28,339	27,218
Deferred Income Taxes	41,703	35,414
Current Portion of Long-Term Debt	220,000	37,000
Other	143,983	137,645
Total	2,220,099	1,345,560
Long-Term Debt	5,003,341	2,760,000
Other Liabilities	667,455	632,652
Deferred Income Taxes	3,501,706	3,382,413
Commitments and Contingencies (Note 7)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 254,223,521 Shares and 252,627,177 Shares Issued at December 31, 2010 and 2009, respectively	202,542	202,526
Additional Paid in Capital	729,992	596,702
Accumulated Other Comprehensive Income	440,071	339,720
Retained Earnings	8,870,179	8,866,747
Common Stock Held in Treasury, 146,186 Shares and 118,525 Shares at December 31, 2010 and 2009, respectively	(11,152)	(7,653)

Total Stockholders' Equity	10,231,632	9,998,042
Total Liabilities and Stockholders' Equity	$21,624,233	$18,118,667

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

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In Thousands, Except Per Share Data)

	Preferred Stock	Common Stock	Additional Paid In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Stockhol Equit
Balance at December 31, 2007	$4,977	$202,495	$221,102	$466,702	$6,156,721	$(61,903)	$6,990,0
Net Income	-	-	-	-	2,436,919	-	2,436,9
Redemption of Preferred Stock	(5,000)	-	-	-	-	-	(5,000
Amortization of Preferred Stock Discount	23	-	-	-	(23)	-	-
Preferred Stock Dividends Declared	-	-	-	-	(420)	-	(420
Common Stock Dividends Declared, $0.51 Per Share	-	-	-	-	(127,054)	-	(127,05
Foreign Currency Translation Adjustments	-	-	-	(431,940)	-	-	(431,94
Foreign Currency Swap Transaction, Net of Tax	-	-	-	(7,195)	-	-	(7,195
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	-	220	-	-	220
Treasury Stock Issued Under Stock Plans, Net	-	-	7,260	-	-	47,649	54,909
Excess Tax Benefits from Stock-Based Compensation	-	-	6,446	-	-	-	6,446
Restricted Stock and Restricted Stock Units, Net	-	3	(8,515)	-	-	8,512	-
Stock-Based Compensation Expenses	-	-	97,493	-	-	-	97,493
Treasury Stock Issued as Compensation	-	-	19	-	-	6	25
Balance at December 31, 2008	-	202,498	323,805	27,787	8,466,143	(5,736)	9,014,4
Net Income	-	-	-	-	546,627	-	546,62
Common Stock Issued Under Stock Plans	-	3	18,641	-	-	-	18,644
Common Stock Dividends Declared, $0.58 Per Share	-	-	-	-	(146,023)	-	(146,02
Foreign Currency Translation Adjustments	-	-	-	308,286	-	-	308,28
Foreign Currency Swap Transaction, Net of Tax	-	-	-	4,817	-	-	4,817
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	-	(1,170)	-	-	(1,170
Treasury Stock Issued Under Stock Plans, Net	-	-	(4,240)	-	-	(4,923)	(9,163
Excess Tax Benefits from Stock-Based Compensation	-	-	76,134	-	-	-	76,134
Restricted Stock and Restricted Stock Units, Net	-	10	(2,483)	-	-	2,473	-
Stock-Based Compensation Expenses	-	-	95,037	-	-	-	95,037
Shares Issued for Property Acquisition	-	15	89,566	-	-	-	89,581
Treasury Stock Issued as Compensation	-	-	242	-	-	533	775

Balance at December 31, 2009	-	202,526	596,702	339,720	8,866,747	(7,653)	9,998,0
Net Income	-	-	-	-	160,654	-	160,654
Common Stock Issued Under Stock Plans	-	10	34,552	-	-	-	34,562
Common Stock Dividends Declared, $0.62 Per Share	-	-	-	-	(157,222)	-	(157,22
Foreign Currency Translation Adjustments	-	-	-	96,179	-	-	96,179
Foreign Currency Swap Transaction, Net of Tax	-	-	-	3,244	-	-	3,244
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	-	(251)	-	-	(251
Interest Rate Swap, Net of Tax	-	-	-	1,179	-	-	1,179
Treasury Stock Issued Under Stock Plans, Net	-	-	(7,257)	-	-	(4,039)	(11,296
Excess Tax Expense from Stock-Based Compensation	-	-	(837)	-	-	-	(837
Restricted Stock and Restricted Stock Units, Net	-	6	(505)	-	-	499	-
Stock-Based Compensation Expenses	-	-	107,314	-	-	-	107,314
Treasury Stock Issued as Compensation	-	-	23	-	-	41	64
Balance at December 31, 2010	$-	$202,542	$729,992	$440,071	$8,870,179	$(11,152)	$10,231,

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

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

Year Ended December 31	2010	2009	2008
Cash Flows from Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	$160,654	$546,627	$2,436,919
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	1,941,926	1,549,188	1,326,875
Impairments	742,647	305,832	192,859
Stock-Based Compensation Expenses	107,378	95,180	97,493
Deferred Income Taxes	76,245	174,392	1,133,630
Gains on Property Dispositions, Net	(223,538)	(535,436)	(123,473)
Other, Net	(468)	6,761	(14,919)
Dry Hole Costs	72,486	51,243	55,167
Mark-to-Market Commodity Derivative Contracts			
Total Gains	(61,912)	(431,757)	(597,911)
Realized Gains (Losses)	7,033	1,277,584	(136,625)
Excess Tax Benefits from Stock-Based Compensation	-	(76,134)	(6,446)
Other, Net	17,273	18,862	13,229
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	(339,126)	(47,818)	95,165
Inventories	(171,791)	(50,146)	(92,049)
Accounts Payable	654,688	(153,565)	30,253
Accrued Taxes Payable	(53,098)	90,929	72,467
Other Assets	(32,169)	(5,515)	(10,715)
Other Liabilities	19,342	(12,305)	9,061
Changes in Components of Working Capital Associated with Investing and Financing Activities	(208,968)	118,517	152,269
Net Cash Provided by Operating Activities	2,708,602	2,922,439	4,633,249
Investing Cash Flows			
Additions to Oil and Gas Properties	(5,210,612)	(3,176,783)	(4,718,860)
Additions to Other Property, Plant and Equipment	(370,770)	(326,226)	(476,611)
Acquisition of Galveston LNG Inc.	(210,000)	-	-
Proceeds from Sales of Assets	672,593	212,000	383,559
Changes in Components of Working Capital Associated with Investing Activities	208,933	(118,221)	(152,374)
Other, Net	7,082	(5,321)	(2,232)
Net Cash Used in Investing Activities	(4,902,774)	(3,414,551)	(4,966,518)
Financing Cash Flows			
Long-Term Debt Borrowings	2,478,659	900,000	750,000
Long-Term Debt Repayments	(37,000)	-	(38,000)
Dividends Paid	(153,240)	(142,260)	(115,204)
Redemption of Preferred Stock	-	-	(5,395)

Excess Tax Benefits from Stock-Based Compensation	-	76,134	6,446
Treasury Stock Purchased	(11,295)	(10,986)	(17,834)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	34,560	20,465	72,572
Debt Issuance Costs	(8,300)	(8,895)	(7,585)
Other, Net	35	(296)	105
Net Cash Provided by Financing Activities	2,303,419	834,162	645,105
Effect of Exchange Rate Changes on Cash	(6,145)	12,390	(34,756)
Increase in Cash and Cash Equivalents	103,102	354,440	277,080
Cash and Cash Equivalents at Beginning of Year	685,751	331,311	54,231
Cash and Cash Equivalents at End of Year	$788,853	$685,751	$331,311

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

EOG RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements of EOG Resources, Inc. (EOG) include the accounts of all domestic and foreign subsidiaries. Investments in unconsolidated affiliates, in which EOG is able to exercise significant influence, are accounted for using the equity method. All intercompany accounts and transactions have been eliminated.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, commodity derivative contracts, accounts receivable, accounts payable and current and long-term debt, along with associated foreign currency and interest rate swaps. The carrying values of cash and cash equivalents, commodity derivative contracts, accounts receivable, foreign currency and interest rate swaps and accounts payable approximate fair value (see Notes 2 and 11).

Cash and Cash Equivalents. EOG records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

Oil and Gas Operations. EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting.

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made (see Note 16). Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account. Certain other assets, including gathering and processing facilities, are depreciated on a straight-line basis over the estimated useful life of the asset.

Assets are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) (ASC Topic 932). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that an asset may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. In certain instances, EOG utilizes accepted bids as the basis for determining fair value.

Inventories, consisting primarily of tubular goods and well equipment held for use in the exploration for and development and production of crude oil and natural gas reserves, are carried at cost with adjustments made from time to time to recognize, as appropriate, any reductions in value.

Arrangements for crude oil and condensate, natural gas liquids and natural gas sales are evidenced by signed contracts with determinable market prices, and revenues are recorded when production is delivered. A significant majority of the purchasers of these products have investment grade credit ratings and material credit losses have been rare. Revenues are recorded on the entitlement method based on EOG's percentage ownership of current production. Each working interest owner in a well generally has the right to a specific percentage of production, although actual production sold on that owner's behalf may differ from that owner's ownership percentage. Under entitlement accounting, a receivable is recorded when underproduction occurs and a payable is recorded when overproduction occurs. Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, natural gas liquids and natural gas, as well as gathering fees associated with gathering third-party natural gas.

Other Property, Plant and Equipment. Other property, plant and equipment consist of gathering and processing assets, compressors, crude oil loading and unloading assets, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software. Other property, plant and equipment is depreciated on a straight-line basis over the estimated useful lives of the property, plant and equipment, which range from 3 years to 40 years.

Capitalized Interest Costs. Interest capitalization is required for those properties if its effect, compared with the effect of expensing interest, is material. Accordingly, certain interest costs have been capitalized as a part of the historical cost of unproved oil and gas properties. The amount capitalized is an allocation of the interest cost incurred during the reporting period. Capitalized interest is computed only during the exploration and development phases and ceases once production begins. The interest rate used for capitalization purposes is based on the interest rates on EOG's outstanding borrowings.

Accounting for Risk Management Activities. EOG accounts for its price risk management activities under the provisions of the Derivatives and Hedging Topic of the ASC (ASC Topic 815). The related provisions establish accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at its fair value. The related provisions require that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. During the three-year period ended December 31, 2010, EOG elected not to designate any of its commodity price risk management activities as accounting hedges under ASC Topic 815, and accordingly, accounted for them using the mark-to-market accounting method. Under this accounting method, the changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change. The gains or losses are recorded in Gains on Mark-to-Market Commodity Derivative Contracts. The related cash flow impact is reflected as cash flows from operating activities. See Note 11. EOG entered into a foreign currency swap transaction in March 2004 and an interest rate swap transaction in November 2010 (see Note 2). EOG employs net presentation of derivative assets and liabilities for financial reporting purposes when such assets and liabilities are with the same counterparty and subject to a master netting arrangement.

Income Taxes. EOG accounts for income taxes under the provisions of the Income Taxes Topic of the ASC (ASC Topic 740). ASC Topic 740 requires the asset and liability approach for accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis (see Note 5).

Foreign Currency Translation. The United States dollar is the functional currency for all of EOG's consolidated subsidiaries except for certain of its Canadian subsidiaries, for which the functional currency is the Canadian dollar, and its United Kingdom subsidiary, for which the functional currency is the British pound. For subsidiaries whose functional currency is deemed to be other than the United States dollar, asset and liability accounts are translated at year-end exchange rates and revenues and expenses are translated at average exchange rates prevailing during the year. Translation adjustments are included in Accumulated Other Comprehensive Income in the Consolidated Balance Sheets. Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period.

Net Income Per Share. Basic net income per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted net income per share is computed based upon the weighted-average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities (see Note 8).

Stock-Based Compensation. In accordance with the provisions of the Stock Compensation Topic of the ASC (ASC Topic 718), EOG measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award.

Recently Issued Accounting Standards and Developments. In January 2010, the FASB issued Accounting Standards Update (ASU) 2010-06, "Improving Disclosures About Fair Value Measurements" (ASU 2010-06), which amends the Fair Value Measurements and Disclosures Topic of the ASC (ASC Topic 820). Among other provisions, ASC Topic 820 establishes a fair value hierarchy that prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. This amendment requires new disclosures on the value of, and the reason for, transfers in and out of Levels 1 and 2 of the fair value hierarchy and additional disclosures about purchases, sales, issuances and settlements within Level 3 fair value measurements. ASU 2010-06 also clarifies existing disclosure requirements on levels of disaggregation and about inputs and valuation techniques. ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009, except for the requirement to provide additional disclosures regarding Level 3 measurements which is effective for interim and annual reporting periods beginning after December 15, 2010. See Note 12.

In January 2010, the FASB issued ASU 2010-03, "Oil and Gas Reserve Estimations and Disclosures" (ASU 2010-03). This update aligns the current oil and gas reserve estimation and disclosure requirements of ASC Topic 932 with the changes required by the United States Securities and Exchange Commission (SEC) final rule, "Modernization of Oil and Gas Reporting," as discussed below. ASU 2010-03 expands the disclosures required for equity method investments, revises the definition of oil- and gas-producing activities to include nontraditional resources in reserves unless not intended to be upgraded into synthetic oil or gas, amends the definition of proved oil and gas reserves to require 12-month average pricing in estimating reserves, amends and adds definitions in the Master Glossary that is used in estimating proved oil and gas quantities and provides guidance on geographic area with respect to disclosure of information about significant reserves. ASU 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. EOG adopted ASU 2010-03 (see Supplemental Information to Consolidated Financial Statements) effective December 31, 2009.

In December 2008, the SEC released a final rule, "Modernization of Oil and Gas Reporting," which amends the oil and gas reporting requirements. The key revisions to the reporting requirements include: using a 12-month average price to determine reserves; including nontraditional resources in reserves if they are intended to be upgraded to synthetic oil and gas; ability to use reliable technologies to determine and estimate reserves; and permitting the optional disclosure of probable and possible reserves. In addition, the final rule includes the requirements to report the independence and qualifications of the reserve preparer or auditor; to file a report as an exhibit when a third party is relied upon to prepare reserve estimates or conduct reserve audits; and to disclose the development of any proved undeveloped reserves (PUDs), including the total quantity of PUDs at year-end, material changes to PUDs during the year, investments and progress toward the development of PUDs and an explanation of the reasons why material concentrations of PUDs have remained undeveloped for five years or more after disclosure as PUDs. The accounting changes resulting from changes in definitions and pricing assumptions should be treated as a change in accounting principle that is inseparable from a change in accounting estimate, which is to be applied prospectively. The final rule is effective for annual reports for fiscal years ending on or after December 31, 2009. EOG adopted the provisions of the new rule effective December 31, 2009.

2. Long-Term Debt

Long-Term Debt at December 31, 2010 and 2009 consisted of the following (in thousands):

		2010	2009
6.125% Senior Notes due 2013		$ 400,000	$ 400,000
Floating Rate Senior Notes due 2014		350,000	-
2.95% Senior Notes due 2015		500,000	-
2.500% Senior Notes due 2016		400,000	-
5.875% Senior Notes due 2017		600,000	600,000
6.875% Senior Notes due 2018		350,000	350,000
5.625% Senior Notes due 2019		900,000	900,000
4.40% Senior Notes due 2020		500,000	-
4.100% Senior Notes due 2021		750,000	-
6.65% Senior Notes due 2028		140,000	140,000
Subsidiary Revolving Credit Facility due 2010		-	37,000
7.00% Subsidiary Debt due 2011		220,000	220,000
4.75% Subsidiary Debt due 2014		150,000	150,000
Total Long-Term Debt		5,260,000	2,797,000
Less:	Current Portion of Long-Term Debt	220,000	37,000
	Unamortized Debt Discount	36,659	-
Total Long-Term Debt, Net		$ 5,003,341	$ 2,760,000

At December 31, 2010, the aggregate annual maturities of long-term debt were $220 million in 2011, zero in 2012, $400 million in 2013, $500 million in 2014 and $500 million in 2015. All subsidiary debt is guaranteed by EOG.

During 2010 and 2009, EOG utilized commercial paper and short-term borrowings under uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper or uncommitted credit facilities at December 31, 2010. The average borrowings outstanding under the commercial paper program and the uncommitted credit facilities were $191 million and $0.1 million, respectively, during the year ended December 31, 2010. The weighted average interest rates for commercial paper and uncommitted credit facility borrowings for 2010 were 0.35% and 0.67%, respectively.

On November 23, 2010, EOG completed its public offering of $400 million aggregate principal amount of 2.500% Senior Notes due 2016 (2016 Notes), $750 million aggregate principal amount of 4.100% Senior Notes due 2021 (2021 Notes) (together, the Fixed Rate Notes) and $350 million aggregate principal amount of Floating Rate Senior Notes due 2014 (the Floating Rate Notes). Interest on the Fixed Rate Notes is payable semiannually in arrears on February 1 and August 1 of each year, beginning on February 1, 2011. Interest on the Floating Rate Notes is payable quarterly in arrears on February 3, May 3, August 3 and November 3 of each year, beginning on February 3, 2011 and is based on the three-month London InterBank Offering Rate (LIBOR) plus 0.75% per annum. The interest rate on the Floating Rate Notes resets quarterly on the interest payment dates. Net proceeds from the offering of approximately $1,487 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings. Contemporaneously with the offering of the Floating Rate Notes, EOG entered into an interest rate swap to fix the interest rate on the Floating Rate Notes at 1.87%. EOG accounts for the interest rate swap using the hedge accounting method, pursuant to the provisions of ASC Topic 815. The fair value of the interest rate swap was $2 million at December 31, 2010. Changes in the fair value of the interest rate swap resulted in no net impact to Net Income Available to Common Stockholders on the Consolidated Statements of Income and Comprehensive Income. The after-tax net impact from the interest rate swap was an increase in Other Comprehensive Income of $1 million.

On May 20, 2010, EOG completed its public offering of $500 million aggregate principal amount of 2.95% Senior Notes due 2015 and $500 million aggregate principal amount of 4.40% Senior Notes due 2020 (together, Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning on December 1, 2010. Net proceeds from the Notes offering of approximately $990 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings.

EOG currently has two $1.0 billion unsecured Revolving Credit Agreements with domestic and foreign lenders. At December 31, 2010, there were no borrowings or letters of credit outstanding under either of these agreements. The first $1.0 billion unsecured Revolving Credit Agreement (2005 Agreement) matures on June 28, 2012. Advances under the 2005 Agreement accrue interest based, at EOG's option, on either the LIBOR plus an applicable margin (Eurodollar rate) or the base rate (as defined in the 2005 Agreement). At December 31, 2010, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2005 Agreement, would have been 0.45% and 3.25%, respectively.

On September 10, 2010, EOG entered into the second $1.0 billion unsecured Revolving Credit Agreement (2010 Agreement). The 2010 Agreement matures on September 10, 2013 (subject to EOG's option to extend, on up to two occasions, the term for successive one-year periods). Advances under the 2010 Agreement accrue interest based, at EOG's option, on either the Eurodollar rate or the base rate (as defined in the 2010 Agreement) plus an applicable margin. At December 31, 2010, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2010 Agreement, would have been 1.84% and 3.83%, respectively. The 2010 Agreement and the 2005 Agreement each contain representations, warranties, covenants and events of default that are customary for investment grade, senior unsecured commercial bank credit agreements, including a financial covenant for the maintenance of a total debt-to-total capitalization ratio of no greater than 65%. There are no other financial covenants in EOG's financing agreements. EOG continues to comply with its financial covenant and does not view it as materially restrictive.

On May 12, 2010, EOG Resources Trinidad Limited, a wholly owned foreign subsidiary of EOG, repaid at maturity the remaining $37 million outstanding balance of its $75 million Revolving Credit Agreement, thereby canceling this agreement. The weighted average interest rate for the amount outstanding during the year ended December 31, 2010 was 2.74%.

On May 21, 2009, EOG completed its public offering of $900 million aggregate principal amount of 5.625% Senior Notes due 2019 (2019 Notes). Interest on the 2019 Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning on December 1, 2009. Net proceeds from the offering of approximately $891 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings.

The 2.95% Senior Notes due 2015, the 2016 Notes, the 2019 Notes, the 4.40% Senior Notes due 2020 and the 2021 Notes were issued through public offerings and have effective interest rates of 3.148%, 2.698%, 5.735%, 4.565%, and 4.276%, respectively.

In March 2004, EOG Resources Canada Inc., a wholly-owned subsidiary of EOG, issued notes with an aggregate principal amount of $150 million, an interest rate of 4.75% and a maturity date of March 15, 2014. In conjunction with the offering, EOG entered into a foreign currency swap transaction with multiple banks for the equivalent amount of the notes and related interest, which has in effect converted this indebtedness into $201.3 million Canadian dollars with a 5.275% interest rate. EOG accounts for the foreign currency swap transaction using the hedge accounting method, pursuant to the provisions of ASC Topic 815. Under those provisions, as of December 31, 2010 and 2009, EOG recorded the fair value of the foreign currency swap of $55 million and $49 million, respectively, in Other Liabilities on the Consolidated Balance Sheets. Changes in the fair value of the foreign currency swap resulted in no net impact to Net Income Available to Common Stockholders on the Consolidated Statements of Income and Comprehensive Income. The after-tax net impact from the foreign currency swap was an increase in Other Comprehensive Income of $3 million and $5 million for the years ended December 31, 2010 and 2009, respectively, and a decrease in Other Comprehensive Income of $7 million for the year ended December 31, 2008.

Fair Value of Debt. At December 31, 2010 and 2009, EOG had outstanding $5,260 million and $2,797 million, respectively, aggregate principal amount of debt, which had estimated fair values of approximately $5,602 million and $3,056 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, upon interest rates available to EOG at year-end.

3. Stockholders' Equity

Common Stock. In September 2001, EOG's Board of Directors (Board) authorized the purchase of an aggregate maximum of 10 million shares of common stock of EOG that superseded all previous authorizations. At December 31, 2010, 6,386,200 shares remained available for purchase under this authorization. EOG last purchased shares of its common stock under this authorization in March 2003. In addition, shares of EOG's common stock are from time to time withheld by, or returned to, EOG in satisfaction of tax withholding obligations arising upon the exercise of employee stock options or stock-settled stock appreciation rights, the vesting of restricted stock or restricted stock unit grants or in payment of the exercise price of employee stock options. Such shares withheld or returned do not count against the Board authorization discussed above. Shares purchased, withheld and returned are held in treasury for, among other purposes, fulfilling any obligations arising under EOG's stock plans and any other approved transactions or activities for which such shares of common stock shall be required.

The Board increased the quarterly cash dividend on EOG's common stock to $0.12 per share on February 7, 2008, to $0.135 per share on July 29, 2008, to $0.145 per share on February 4, 2009 and to $0.155 per share on February 9, 2010. On February 17, 2011, EOG's Board increased the quarterly cash dividend on the common stock from the current $0.155 per share to $0.16 per share effective beginning with the dividend to be paid on April 29, 2011 to stockholders of record as of April 15, 2011.

The following summarizes EOG's common stock activity for each of the years ended December 31, 2008, 2009 and 2010 (in thousands):

	Common Shares		
	Issued	Treasury	Outstanding
Balance at December 31, 2007	249,460	(2,935)	246,525
Common Stock Issued Under Equity Compensation Plans	299	-	299
Treasury Stock Purchased (1)	-	(195)	(195)
Treasury Stock Issued Under Employee Stock Purchase Plan	-	103	103
Treasury Stock Issued Under Other Equity Compensation Plans	-	2,900	2,900
Balance at December 31, 2008	249,759	(127)	249,632
Common Stock Issued Under Equity Compensation Plans	1,347	-	1,347
Treasury Stock Purchased (1)	-	(168)	(168)
Common Stock Issued Under Employee Stock Purchase Plan	71	-	71
Treasury Stock Issued Under Other Equity Compensation Plans	-	177	177
Common Stock Issued for Property Acquisition	1,450	-	1,450
Balance at December 31, 2009	252,627	(118)	252,509
Common Stock Issued Under Equity Compensation Plans	1,482	-	1,482
Treasury Stock Purchased (1)	-	(115)	(115)
Common Stock Issued Under Employee Stock Purchase Plan	114	-	114
Treasury Stock Issued Under Other Equity Compensation Plans	-	87	87
Balance at December 31, 2010	254,223	(146)	254,077

(1) Represents shares that were withheld by, or returned to, EOG in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights, the vesting of restricted stock or restricted stock unit grants or in payment of the exercise price of employee stock options.

Preferred Stock. EOG currently has one authorized series of preferred stock. In February 2000, EOG's Board, in connection with the Rights Agreement, authorized 1,500,000 shares of the Series E Junior Participating Preferred Stock (Series E). In February 2005, EOG's Board increased the authorized shares of the Series E to 3,000,000 in connection with the two-for-one stock split of EOG's common stock effected in March 2005. As of December 31, 2010, there were no shares of the Series E outstanding. The Rights Agreement and the related preferred share purchase rights expired on February 24, 2010.

In July 2000, EOG's Board authorized 100,000 shares of 7.195% Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 liquidation preference per share (Series B). Dividends were payable quarterly, in cash, on the shares of the Series B as declared by EOG's Board at a rate of $71.95 per share per year, on March 15, June 15, September 15 and December 15 of each year. In separate transactions in 2007 and 2008, EOG purchased all of the outstanding shares of the Series B. In March 2008, EOG filed a certificate of elimination with respect to the Series B with the Delaware Secretary of State, eliminating all matters with respect to the Series B from EOG's restated certificate of incorporation and effectively eliminating the Series B as an authorized series of EOG's preferred stock.

4. Other Income, Net

Other income, net for 2010 included equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants ($13 million), net foreign currency transaction gains ($4 million) and losses on sales of warehouse stock ($4 million). Other income, net for 2009 included equity income from investments in the CNCL and N2000 ammonia plants ($4 million), net foreign currency transaction gains ($4 million) and losses on sales of warehouse stock ($4 million).

5. Income Taxes

The principal components of EOG's net deferred income tax liabilities at December 31, 2010 and 2009 were as follows (in thousands):

	2010	2009
Current Deferred Income Tax Assets (Liabilities)		
Commodity Hedging Contracts	$(7,141)	$-
Deferred Compensation Plans	13,216	-
Other	3,185	-
Total Net Current Deferred Income Tax Assets	$9,260	$-
Noncurrent Deferred Income Tax Assets (Liabilities)		
United Kingdom Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$(16,611)	$-
United Kingdom Net Operating Loss	17,329	-
United Kingdom Other	226	-
Total Net Noncurrent Deferred Income Tax Assets	$944	$-
Current Deferred Income Tax (Assets) Liabilities		
Commodity Hedging Contracts	$-	$11,559
Deferred Compensation Plans	-	(11,121)
Timing Differences Associated with Different Year-ends in Foreign Jurisdictions	41,027	27,659
Other	676	7,317
Total Net Current Deferred Income Tax Liabilities	$41,703	$35,414
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$4,373,110	$3,746,302
Non-Producing Leasehold Costs	(78,846)	(67,347)
Seismic Costs Capitalized for Tax	(92,901)	(64,917)
Equity Awards	(99,447)	(76,978)
Capitalized Interest	94,957	76,852
Net Operating Loss	(498,893)	-
Alternative Minimum Tax Credit Carryforward	(214,873)	(200,034)
Other	18,599	(31,465)
Total Net Noncurrent Deferred Income Tax Liabilities	$3,501,706	$3,382,413
Total Net Deferred Income Tax Liabilities	$3,533,205	$3,417,827

The components of Income Before Income Taxes for the years indicated below were as follows (in thousands):

	2010	2009	2008
United States	$646,495	$784,248	$3,138,175
Foreign	(238,519)	87,763	608,364
Total	$407,976	$872,011	$3,746,539

The principal components of EOG's Income Tax Provision for the years indicated below were as follows (in thousands):

	2010	2009	2008
Current:			
Federal	$17,154	$95,194	$50,776
State	(1,642)	8,783	5,674
Foreign	155,565	47,015	119,540
Total	171,077	150,992	175,990
Deferred:			
Federal	190,602	166,045	1,010,535
State	60,619	31,580	56,540
Foreign	(174,976)	(23,233)	66,555
Total	76,245	174,392	1,133,630
Income Tax Provision	$247,322	$325,384	$1,309,620

The differences between taxes computed at the United States federal statutory tax rate and EOG's effective rate were as follows:

	2010	2009	2008
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	9.39	3.00	1.08
Income Tax Provision Related to Foreign Operations	(0.03)	(1.40)	(0.83)
Income Tax Provision Related to Trinidad Operations	6.26	0.60	0.11
Canadian Shallow Natural Gas Impairments	9.49	-	-
Other	0.51	0.11	(0.40)
Effective Income Tax Rate	60.62%	37.31%	34.96%

The difference in the effective tax rate and the United States federal statutory rate of 35% is attributed principally to state and foreign income taxes. The state income tax rate has increased due to the expansion of EOG's operations in higher taxed states. The largest component of the increase in the state tax expense is attributable to the redetermination of the deferred state tax liability, which was increased to reflect expected higher effective state tax rates due to EOG's change in commercial operations within the United States. The increase in the foreign tax rate is related to a greater proportion of EOG's worldwide income being earned in Trinidad, which has a corporate tax rate higher than 35%, and to impairments of certain Canadian shallow natural gas assets, the tax benefit of which is calculated at a rate lower than 35%.

The balance of unrecognized tax benefits at December 31, 2010 was $25 million, all of which, if recognized, would affect the effective tax rate. EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. Currently, there are no amounts of interest or penalties recognized in the Consolidated Statements of Income and Comprehensive Income or in the Consolidated Balance Sheets. EOG does not anticipate that the amount of the unrecognized tax benefits will significantly change during the next twelve months. EOG and its subsidiaries file income tax returns in the United States and various state, local and foreign jurisdictions. EOG is generally no longer subject to income tax examinations by tax authorities in the United States (federal), Canada, the United Kingdom, Trinidad and China for taxable years before 2005, 2006, 2009, 2003 and 2008, respectively.

EOG's foreign subsidiaries' undistributed earnings of approximately $2.6 billion at December 31, 2010 are considered to be indefinitely invested outside the United States and, accordingly, no United States federal or state income taxes have been provided thereon. Upon distribution of those earnings, EOG may be subject to both foreign withholding taxes and United States income taxes, net of allowable foreign tax credits. The amount of such additional taxes would be dependent on several factors, including the size and timing of the distribution, the particular foreign jurisdiction from which the distribution is made, and the availability of foreign tax credits. As a result, the determination of the potential amount of unrecognized withholding and deferred income taxes is not practicable, though additional taxes resulting from a repatriation of foreign earnings could be significant.

In 2010, EOG generated a regular tax net operating loss of $1.4 billion, which is expected to be carried forward and applied against regular taxable income in future periods. ASC Topic 718, which relates to accounting for stock-based compensation, provides that when settlement of a stock award contributes to a net operating loss carryforward, neither the associated excess tax benefit nor the credit to additional paid in capital (APIC) should be recorded until the stock award deduction reduces income taxes payable. Upon utilization of the loss in future periods, a benefit of $17 million will be reflected in APIC. In 2010, EOG paid alternative minimum tax (AMT) of $17 million. The AMT paid in 2010, along with AMT of $198 million paid in prior years (including $19 million and $84 million related to 2009 and 2008, respectively), will be carried forward as a credit available to offset regular income taxes in future periods.

During 2010, EOG incurred a foreign tax net operating loss of approximately $35 million. This net operating loss will be carried forward indefinitely.

6. Employee Benefit Plans

Pension Plans and Postretirement Benefits

At December 31, 2010, EOG and its subsidiaries in Canada and Trinidad maintained certain defined benefit pension and postretirement medical plans covering certain eligible employees. EOG plan assets and benefit obligations are currently measured as of the date of EOG's fiscal year-end. During 2010, approximately $0.2 million from such plans was amortized from Accumulated Other Comprehensive Income through net periodic benefit costs.

Pension Plans. EOG has a non-contributory defined contribution pension plan and a matched defined contribution savings plan in place for most of its employees in the United States. EOG's contributions to these pension plans are based on various percentages of compensation and, in some instances, are based upon the amount of the employees' contributions. EOG's total costs recognized for these plans were $23 million, $22 million and $20 million for 2010, 2009 and 2008, respectively.

In addition, EOG's Canadian subsidiary maintains both a non-contributory defined benefit pension plan and a non-contributory defined contribution pension plan, as well as a matched defined contribution savings plan. EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. With the exception of Canada's non-contributory defined benefit pension plan, which is closed to new employees, these pension plans are available to most employees of the Canadian and Trinidadian subsidiaries. EOG's combined contributions to these plans were $2.5 million, $2.3 million and $2.7 million for 2010, 2009 and 2008, respectively.

For the Canadian and Trinidadian defined benefit pension plans, the benefit obligation, fair value of plan assets and prepaid/(accrued) benefit cost totaled $10.3 million, $8.7 million and $(0.8) million, respectively, at December 31, 2010 and $9.1 million, $7.7 million and $(0.9) million, respectively, at December 31, 2009. Weighted average discount rate, expected return on plan assets, rate of compensation increase and rate of pension increase assumptions used to determine net periodic benefit cost for the pension plans were 6.25%, 7.00%, 4.88% and 0.00%, respectively, at December 31, 2010; 7.87%, 7.99%, 5.73% and 1.51%, respectively, at December 31, 2009 and 7.90%, 8.05%, 5.80% and 1.46%, respectively, at December 31, 2008. Weighted average discount rate, rate of compensation increase and rate of pension increase assumptions used to determine benefit obligations for the pension plans were 5.42%, 3.85% and 0.00%, respectively, for the year ended December 31, 2010 and 5.76%, 4.14% and 1.74%, respectively, for the year ended December 31, 2009. The weighted average asset allocation at December 31, 2010 consisted of equities (46%), debt and fixed income securities (43%) and other assets (11%). The weighted average asset allocation at December 31, 2009 consisted of equities (46%), debt and fixed income securities (44%) and other assets (10%).

The fair value of the Canadian subsidiary's pension plan assets was $5.6 million at December 31, 2010. Such assets consisted of mutual funds valued using Level 1 inputs, which represent quoted market prices in active markets. The fair value of the Trinidadian subsidiary's pension plan assets was $3.1 million at December 31, 2010. Such assets consisted of cash in other currencies ($734 million), cash in United States dollars ($94 million) and foreign equities ($131 million) valued using Level 1 inputs, as well as bonds ($1,721 million), local equities ($373 million) and regional equities ($43 million) valued using Level 2 inputs, which represent indirectly observable inputs other than quoted market prices (see Note 12).

The investment policy for the defined benefit pension plan of EOG's Trinidadian subsidiary is determined by the pension plan's trustee, with input from EOG. The plan's asset allocation policy is largely dictated by local statutory requirements which restrict total investment in equities to a maximum of 50% of the plan's assets and investment overseas to 20% of the plan's assets. The investment policy for the defined benefit pension plan of EOG's Canadian subsidiary provides that EOG shall invest the plan assets in one or more balanced funds with Canadian and foreign equity components as deemed appropriate for the purpose of diversification.

EOG's United Kingdom subsidiary maintains a pension plan which includes a non-contributory defined contribution pension plan and a matched defined contribution savings plan. The pension plan is available to all employees of the United Kingdom subsidiary. EOG's combined contributions to these pension plans were approximately $0.1 million for each of the years 2010, 2009 and 2008.

Postretirement Health Care. EOG has postretirement medical and dental benefits in place for eligible United States and Trinidad employees and their eligible dependents. EOG accrues these postretirement benefit costs over the service lives of the employees expected to be eligible to receive such benefits.

The benefit obligation and accrued benefit cost for the postretirement benefit plans each totaled $6.0 million at December 31, 2010 and $5.2 million and $5.1 million at December 31, 2009, respectively. Weighted average discount rate assumptions used to determine benefit obligations for the postretirement plans at December 31, 2010 and 2009 were 5.20% and 5.83%, respectively. Weighted average discount rate assumptions used to determine net periodic benefit cost for the years ended December 31, 2010, 2009 and 2008 were 5.83%, 6.28% and 6.33%, respectively. Net periodic benefit cost recognized for the postretirement benefit plans totaled $0.9 million, $0.8 million and $0.8 million for the years ended December 31, 2010, 2009 and 2008.

Estimated Future Employer-Paid Benefits. The following benefits, which reflect expected future service, as appropriate, are expected to be paid by EOG in the next 10 years (in thousands):

	Pension Plans	Postretirement Plans
2011	$296	$ 214
2012	301	232
2013	328	272
2014	508	317
2015	451	343
2016 - 2020	3,082	2,216

Postretirement health care trend rates had minimal effect on the amounts reported for the postretirement health care plans for both 2010 and 2009. Most future increases or decreases in healthcare costs would be borne by the employee.

Stock-Based Compensation

During 2010, EOG maintained various stock-based compensation plans as discussed below. EOG recognizes compensation expense on grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock and restricted stock units and grants made under its Employee Stock Purchase Plan (ESPP). Stock-based compensation expense is calculated based upon the grant date estimated fair value of the awards, net of forfeitures, based upon EOG's historical employee turnover rate. For awards made prior to January 1, 2006, compensation expense is amortized over the vesting period on a straight-line basis. For awards made subsequent to January 1, 2006, compensation expense is amortized over the shorter of the vesting period or the period from date of grant until the date the employee becomes eligible to retire without company approval.

Stock-based compensation expense is included in the Consolidated Statements of Income and Comprehensive Income based upon job functions of the employees receiving the grants. Compensation expense related to EOG's stock-based compensation plans for the years ended December 31, 2010, 2009 and 2008 was as follows (in millions):

	2010	2009	2008
Lease and Well	$27	$23	$20
Gathering and Processing Costs	1	-	-
Exploration Costs	24	21	18
General and Administrative	55	51	59
Total	$107	$95	$97

EOG's stockholders approved the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan at the 2008 Annual Meeting of Stockholders in May 2008. At the 2010 Annual Meeting of Stockholders in April 2010 (2010 Annual Meeting), an amendment to the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, as amended (2008 Plan), was approved, pursuant to which the number of shares of common stock available for future grants of stock options, SARs, restricted stock, restricted stock units and other stock-based awards under the 2008 Plan was increased by an additional 6.9 million shares, to an aggregate maximum of 12.9 million shares plus shares underlying forfeited or cancelled grants under the prior stock plans. At December 31, 2010, approximately 7.1 million common shares remained available for grant under the 2008 Plan. Effective with the adoption of the 2008 Plan, EOG's policy is to issue shares related to the 2008 Plan from previously authorized unissued shares.

During 2010, 2009 and 2008, EOG issued treasury shares in connection with stock option/SAR exercises, restricted stock grants, restricted stock unit releases and ESPP purchases. The difference between the cost of the treasury shares and the exercise price of the options is reflected as an adjustment to APIC to the extent EOG has accumulated APIC relating to treasury stock and to retained earnings thereafter. Additionally, EOG recognized, as an adjustment to APIC, federal income tax (expense)/benefits of $(1) million, $76 million and $6 million for 2010, 2009 and 2008, respectively, related to the exercise of stock options/SARs and the release of restricted stock and restricted stock units.

Stock Options and Stock Appreciation Rights and Employee Stock Purchase Plan. Participants in EOG's stock plans (including the 2008 Plan) have been or may be granted options to purchase shares of common stock of EOG. In addition, participants in EOG's stock plans (including the 2008 Plan) have been or may be granted SARs, representing the right to receive shares of EOG common stock based on the appreciation in the stock price from the date of grant on the number of SARs granted. Stock options and SARs are granted at a price not less than the market price of the common stock on the date of grant. Stock options and SARs granted vest on a graded vesting schedule up to four years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Terms for stock options and SARs granted have not exceeded a maximum term of 10 years. EOG's ESPP allows eligible employees to semi-annually purchase, through payroll deductions, shares of EOG common stock at 85 percent of the fair market value at specified dates. Contributions to the ESPP are limited to 10 percent of the employee's pay (subject to certain ESPP limits) during each of the two six-month offering periods each year.

The fair value of all ESPP grants is estimated using the Black-Scholes-Merton model. Certain of EOG's stock options granted in 2005 contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price of EOG's common stock reaches 200% of the grant price for five consecutive trading days (Capped Option). EOG may or may not issue Capped Options in the future. The fair value of each Capped Option grant was estimated using a Monte Carlo simulation. The fair value of stock option grants not containing the Capped Option feature and SAR grants was estimated using the Hull-White II binomial option pricing model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $41 million, $38 million and $39 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2010, 2009 and 2008 were as follows:

	Stock Options/SARs			ESPP		
	2010	2009	2008	2010	2009	2008
Weighted Average Fair Value of Grants	$32.12	$30.13	$32.19	$25.45	$25.78	$29.68
Expected Volatility	39.70 %	41.90 %	38.55 %	38.30 %	78.89 %	37.58 %
Risk-Free Interest Rate	0.87 %	1.42 %	2.53 %	0.18 %	0.25 %	2.64 %
Dividend Yield	0.70 %	0.70 %	0.60 %	0.70 %	1.00 %	0.50 %
Expected Life	5.5 yrs	5.5 yrs	5.3 yrs	0.5 yrs	0.5 yrs	0.5 yrs

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

The following table sets forth the stock option and SAR transactions for the years ended December 31, 2010, 2009 and 2008 (stock options and SARs in thousands):

	2010		2009		2008	
	Number of Stock Options/ SARs	Weighted Average Grant Price	Number of Stock Options/ SARs	Weighted Average Grant Price	Number Of Stock Options/ SARs	Weighted Average Grant Price
Outstanding at January 1	8,335	$57.08	7,802	$52.56	9,373	$41.04
Granted	1,450	93.07	1,270	80.95	1,231	90.57
Exercised (1)	(1,144)	43.38	(636)	46.56	(2,628)	28.19
Forfeited	(196)	84.22	(101)	74.07	(174)	69.22
Outstanding at December 31	8,445	64.49	8,335	57.08	7,802	52.56
Stock Options/SARs Exercisable at December 31	5,439	51.71	5,394	44.45	4,711	37.23
Available for Future Grant	7,054		2,222		4,555	

(1)

The total intrinsic value of stock options/SARs exercised during the years 2010, 2009 and 2008 was $66.0 million, $21.4 million and $217.9 million, respectively. The intrinsic value is based upon the difference between the market price of EOG common stock on the date of exercise and the grant price of the stock options/SARs.

At December 31, 2010, there were 8,208,698 stock options/SARs vested or expected to vest with a weighted average grant price of $63.83, an intrinsic value of $230 million and a weighted average remaining contractual life of 3.8 years.

The following table summarizes certain information for the stock options and SARs outstanding at December 31, 2010 (stock options and SARs in thousands):

	Stock Options/SARs Outstanding				Stock Options/SARs Exercisable			
Range of Grant Prices	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value(1)	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value(1)
$7.00 to $ 17.99	915	1	$17.44		915	1	$17.44	
18.00 to 48.99	1,085	3	21.69		1,085	3	21.69	
49.00 to 69.99	1,972	2	61.96		1,950	2	61.92	
70.00 to 81.99	2,024	5	78.02		966	4	75.93	
82.00 to 136.99	2,449	6	91.88		523	4	91.12	
	8,445	4	64.49	$231,202	5,439	3	51.71	$217,112

(1) Based upon the difference between the closing market price of EOG common stock on the last trading day of the year and the grant price of in-the-money stock options and SARs.

At December 31, 2010, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $86.5 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.8 years.

At the 2010 Annual Meeting, an amendment to the ESPP was approved to increase the shares available for grant by 1.0 million shares. The ESPP was originally approved by EOG's stockholders in 2001, and would have expired on July 1, 2011. The amendment also extended the term of the ESPP to December 31, 2019, unless terminated earlier by its terms or by EOG. EOG had previously suspended the ESPP, effective for the July 1, 2009 to December 31, 2009 offering period, due to an insufficient number of shares then remaining available under the ESPP. As a result of stockholder approval at the 2010 Annual Meeting of the above-referenced amendment to the ESPP to increase the shares available under the ESPP, EOG resumed the ESPP beginning with the January 1, 2010 to June 30, 2010 offering period. The following table summarizes ESPP activities for the years ended December 31, 2010, 2009 and 2008 (in thousands, except number of participants):

	2010	2009	2008
Approximate Number of Participants	1,236	1,128	1,075
Shares Purchased	114	72	103
Aggregate Purchase Price	$9,172	$4,150	$6,724

Restricted Stock and Restricted Stock Units. Employees may be granted restricted (non-vested) stock and/or restricted stock units without cost to them. The restricted stock and restricted stock units generally vest five years after the date of grant, except for certain bonus grants, and as defined in individual grant agreements. Upon vesting of restricted stock, common shares are released to the employee. Upon vesting, restricted stock units are converted into common shares and released to the employee. Stock-based compensation expense related to restricted stock and restricted stock units totaled $66 million, $57 million and $58 million for the years ended December 31, 2010, 2009 and 2008, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2010, 2009 and 2008 (shares and units in thousands):

	2010		2009		2008	
	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	3,636	$73.69	3,048	$70.24	3,000	$50.61
Granted	850	93.39	1,197	63.13	795	106.67
Released(1)	(364)	58.00	(553)	31.35	(623)	22.77
Forfeited	(113)	79.37	(56)	78.18	(124)	67.42
Outstanding at December 31(2)	4,009	79.13	3,636	73.69	3,048	70.24

(1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2010, 2009 and 2008 was $35.2 million, $36.9 million and $55.7 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and restricted stock units are released.
(2) The aggregate intrinsic value of restricted stock and restricted stock units outstanding at December 31, 2010 and 2009 was approximately $366.4 million and $353.8 million, respectively.

At December 31, 2010, unrecognized compensation expense related to restricted stock and restricted stock units totaled $145.1 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.7 years.

7. Commitments and Contingencies

Letters of Credit. At December 31, 2010, EOG had standby letters of credit and guarantees outstanding totaling approximately $657 million, of which $370 million represents guarantees of subsidiary indebtedness (see Note 2) and $287 million primarily represents guarantees of payment obligations on behalf of subsidiaries. At December 31, 2009, EOG had standby letters of credit and guarantees outstanding totaling approximately $681 million, of which $407 million represents guarantees of subsidiary indebtedness (see Note 2) and $274 million primarily represents guarantees of payment obligations on behalf of subsidiaries. As of February 24, 2011, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2010, total minimum commitments from long-term non-cancelable operating leases, drilling rig commitments, seismic purchase and other purchase obligations, and pipeline transportation service commitments, based on current pipeline transportation rates and the foreign currency exchange rates used to convert Canadian dollars and British pounds into United States dollars at December 31, 2010, are as follows (in thousands):

	Total Minimum Commitments
2011	$ 1,069,861
2012 - 2013	1,007,273
2014 - 2015	856,481
2016 and beyond	1,685,288
	$ 4,618,903

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2025. Rental expenses associated with existing leases amounted to $95 million, $77 million and $70 million for 2010, 2009 and 2008, respectively.

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

8. Net Income Per Share Available to Common Stockholders

The following table sets forth the computation of Net Income Per Share Available to Common Stockholders for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per share data):

	2010	2009	2008
Numerator for Basic and Diluted Earnings per Share -			
Net Income	$160,654	$546,627	$2,436,919
Less: Preferred Stock Dividends	-	-	443
Net Income Available to Common Stockholders	$160,654	$546,627	$2,436,476
Denominator for Basic Earnings per Share -			
Weighted Average Shares	250,876	248,996	246,662
Potential Dilutive Common Shares -			
Stock Options/SARs	1,991	1,691	2,629
Restricted Stock and Restricted Stock Units	1,633	1,197	1,251
Denominator for Diluted Earnings per Share -			
Adjusted Diluted Weighted Average Shares	254,500	251,884	250,542
Net Income Per Share Available to Common Stockholders			
Basic	$0.64	$2.20	$9.88
Diluted	$0.63	$2.17	$9.72

The diluted earnings per share calculation excludes stock options and SARs that were anti-dilutive. The excluded stock options and SARs totaled 0.3 million, 2.5 million and 0.1 million for the years ended December 31, 2010, 2009 and 2008, respectively.

9. Supplemental Cash Flow Information

Net cash paid for interest and income taxes was as follows for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	2010	2009	2008
Interest, Net of Capitalized Interest	$146,731	$100,939	$48,029
Income Taxes, Net of Refunds Received	$233,462	$51,684	$94,598

Non-cash investing activities for the year ended December 31, 2010 included non-cash additions of $3 million to EOG's oil and gas properties in connection with contingent consideration related to EOG's acquisition of certain unproved properties (see Note 17).

Non-cash investing and financing activities for the year ended December 31, 2009 included the following (see Note 17):

- the issuance of 1,450,000 shares of EOG common stock valued at $90 million at the transaction closing date in connection with EOG's purchase of certain proved developed and undeveloped reserves and unproved acreage;
- non-cash additions to EOG's oil and gas properties in the amount of $353 million in connection with EOG's asset exchange agreement; and

- non-cash additions to EOG's oil and gas properties in connection with contingent consideration valued at $35 million at December 31, 2009 in connection with EOG's acquisition of certain unproved properties.

10. Business Segment Information

EOG's operations are all crude oil and natural gas exploration and production related. The Segment Reporting Topic of the ASC establishes standards for reporting information about operating segments in annual financial statements. Operating segments are defined as components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker, or decision-making group, in deciding how to allocate resources and in assessing performance. EOG's chief operating decision making process is informal and involves the Chairman of the Board and Chief Executive Officer and other key officers. This group routinely reviews and makes operating decisions related to significant issues associated with each of EOG's major producing areas in the United States, Canada, Trinidad, the United Kingdom and China. For segment reporting purposes, the chief operating decision maker considers the major United States producing areas to be one operating segment.

Financial information by reportable segment is presented below as of and for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	United States	Canada	Trinidad	Other International (1)	Total
2010					
Crude Oil and Condensate	$ 1,700,770	$ 178,349	$ 117,605	$ 2,047	$ 1,998,771
Natural Gas Liquids	448,647	13,698	-	-	462,345
Natural Gas	1,778,823	285,369	330,247	25,660	2,420,099
Gains on Mark-to-Market Commodity Derivative Contracts	61,912	-	-	-	61,912
Gathering, Processing and Marketing	909,660	-	20	-	909,680
Gains on Property Dispositions, Net	196,774	23,112	3,652	-	223,538
Other, Net	19,886	(31)	3,696	-	23,551
Net Operating Revenues (2)	5,116,472	500,497	455,220	27,707	6,099,896
Depreciation, Depletion and Amortization	1,539,240	315,849	71,085	15,752	1,941,926
Operating Income (Expense)	787,422	(516,874)	312,128	(59,357)	523,319
Interest Income	152	387	120	164	823
Other Income (Expense)	(3,905)	2,067	14,022	1,236	13,420
Net Interest Expense	112,226	34,350	448	(17,438)	129,586
Income (Loss) Before Income Taxes	671,443	(548,770)	325,822	(40,519)	407,976
Income Tax Provision (Benefit)	255,945	(146,495)	140,934	(3,062)	247,322
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	4,491,897	446,626	134,198	65,405	5,138,126
Total Property, Plant and Equipment, Net	15,747,808	2,189,961	595,970	147,161	18,680,900
Total Assets	17,762,533	2,598,412	954,391	308,897	21,624,233

2009													
Crude Oil and Condensate	$	945,224		$	86,140		$	57,089		$	1,258		$	1,089,711
Natural Gas Liquids		246,821			11,978			-			-			258,799
Natural Gas		1,540,042			315,792			172,560			22,569			2,050,963
Gains on Mark-to-Market Commodity Derivative Contracts		431,757			-			-			-			431,757
Gathering, Processing and Marketing		407,097			-			19			-			407,116
Gains on Property Dispositions, Net		535,295			141			-			-			535,436
Other, Net		9,693			(16	)		3,500			-			13,177
Net Operating Revenues (2)		4,115,929			414,035			233,168			23,827			4,786,959
Depreciation, Depletion and Amortization		1,282,180			211,514			47,119			8,375			1,549,188
Operating Income (Expense)		896,937			(31,767	)		143,993			(38,322	)		970,841
Interest Income		137			612			146			205			1,100
Other Income (Expense)		(7,396	)		5,212			4,387			(1,232	)		971
Net Interest Expense		84,411			28,934			1,332			(13,776	)		100,901
Income (Loss) Before Income Taxes		805,267			(54,877	)		147,194			(25,573	)		872,011
Income Tax Provision (Benefit)		290,473			(27,073	)		57,363			4,621			325,384
Additions to Oil and Gas Properties, Excluding Dry Hole Costs		2,770,482			268,604			31,219			55,235			3,125,540
Total Property, Plant and Equipment, Net		12,769,240			2,740,473			532,989			96,523			16,139,225
Total Assets		14,108,129			2,888,949			813,901			307,688			18,118,667

	United States	Canada	Trinidad	Other International (1)	Total
2008					
Crude Oil and Condensate	$ 1,259,667	$ 88,108	$ 107,878	$ 1,970	$ 1,457,623
Natural Gas Liquids	292,496	19,807	-	-	312,303
Natural Gas	3,497,620	619,792	285,184	49,462	4,452,058
Gains on Mark-to-Market Commodity Derivative Contracts	597,911	-	-	-	597,911
Gathering, Processing and Marketing	164,535	-	-	-	164,535
Gains (Losses) on Property Dispositions, Net	129,011	(1,894)	(3,644)	-	123,473
Other, Net	18,193	1,002	45	-	19,240
Net Operating Revenues (2)	5,959,433	726,815	389,463	51,432	7,127,143
Depreciation, Depletion and Amortization	1,100,917	189,796	26,596	9,566	1,326,875
Operating Income (Expense)	3,183,547	306,967	286,600	(9,929)	3,767,185
Interest Income	1,589	2,703	2,641	1,793	8,726
Other Income (Expense)	7,961	(2,111)	18,868	(2,432)	22,286
Net Interest Expense	29,586	27,195	6,150	(11,273)	51,658
Income Before Income Taxes	3,163,511	280,364	301,959	705	3,746,539
Income Tax Provision (Benefit)	1,131,631	68,593	110,242	(846)	1,309,620
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	4,094,265	464,836	86,907	17,685	4,663,693
Total Property, Plant and Equipment, Net	10,771,911	2,298,823	539,576	46,992	13,657,302
Total Assets	12,668,763	2,421,979	735,387	125,097	15,951,226

(1) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(2) EOG had no purchasers in 2010, 2009 or 2008 whose sales totaled 10 percent or more of consolidated Net Operating Revenues.

11. Risk Management Activities

Commodity Price Risks. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, collar and basis swap contracts, as a means to manage this price risk. In addition to financial transactions, EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. Under the provisions of ASC Topic 815 (Derivatives and Hedging), 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.

During 2010, 2009 and 2008, EOG elected not to designate any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounted for these financial commodity derivative contracts using the mark-to-market accounting method. During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net realized gains of $7 million. During 2009, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $432 million, which included net realized gains of $1,278 million. During 2008, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $598 million, which included net realized losses of $137 million.

At December 31, 2010, the fair value of EOG's financial commodity derivative contracts was reflected in the Consolidated Balance Sheets as Current Assets - Assets from Price Risk Management Activities ($48 million), Other Assets ($20 million), Current Liabilities - Liabilities from Price Risk Management Activities ($28 million) and Other Liabilities ($1 million). At December 31, 2009, the fair value of EOG's financial commodity derivative contracts was reflected in the Consolidated Balance Sheets as Current Assets - Assets From Price Risk Management Activities ($21 million), Current Liabilities - Liabilities from Price Risk Management Activities ($27 million) and Other Liabilities ($10 million).

Financial Price Swap Contracts. Presented below is a comprehensive summary of EOG's crude oil and natural gas financial price swap contracts at December 31, 2010, with notional volumes expressed in barrels per day (Bbld) and in million British thermal units per day (MMBtud) and prices expressed in dollars per barrel ($/Bbl) and in dollars per million British thermal units ($/MMBtu), as applicable.

Financial Price Swap Contracts

	Crude Oil		Natural Gas	
	Volume (Bbld)	Weighted Average Price ($/Bbl)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2011 (1)				
January 2011 (2)	17,000	$ 90.44	275,000	$ 5.19
February 1, 2011 through December 31, 2011	17,000	90.44	325,000	5.13
2012 (3)				
January 1, 2012 through December 31, 2012	-	$ -	250,000	$ 5.56

(1) Natural gas financial price swap contracts include unexercised swaption contracts which give counterparties the option of entering into price swap contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas financial price swap contracts will increase by 175,000 MMBtud at an average price of $4.86 per million British thermal units (MMBtu) for the period from February 1, 2011 through December 31, 2011.

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

(3) Natural gas financial price swap contracts include unexercised swaption contracts which give counterparties the option of entering into price swap contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas financial price swap contracts will increase by 150,000 MMBtud at an average price of $5.64 per MMBtu for each month of 2012.

Financial Basis Swap Contracts. Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG has entered into natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at December 31, 2010. The weighted average price differential represents the amount of reduction to NYMEX gas prices per MMBtu for the notional volumes covered by the basis swap.

Natural Gas Financial Basis Swap Contracts

	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)
2011		
First Quarter (1)	65,000	$ (1.89)

(1) Includes closed contracts for the month of January 2011.

Foreign Currency Exchange Rate Risk. EOG is party to a foreign currency swap transaction with multiple banks to eliminate any exchange rate impacts that may result from the $150 million principal amount of notes issued by one of EOG's Canadian subsidiaries. EOG accounts for the foreign currency swap transaction using the hedge accounting method, pursuant to the provisions of ASC Topic 815. See Note 2.

Interest Rate Derivatives. EOG is a party to an interest rate swap transaction with a counterparty bank. The interest rate swap transaction was entered into in order to mitigate EOG's exposure to volatility in interest rates related to EOG's Floating Rate Notes issued on November 23, 2010. The interest rate swap has a notional amount of $350 million and a fair value at December 31, 2010 of $2 million. EOG accounts for the interest rate swap transaction using the hedge accounting method, pursuant to the provisions of ASC Topic 815. See Note 2.

The following table sets forth the amounts, on a gross basis, and classification of EOG's outstanding derivative financial instruments at December 31, 2010 and December 31, 2009. Certain amounts may be presented on a net basis in the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

		Fair Value at December 31,	
Description	Location on Balance Sheet	2010	2009
Asset Derivatives			
Natural gas price swaps -			
Current portion	Assets from Price Risk		
	Management Activities	$ 51	$ 50
Noncurrent portion	Other Assets	$ 18	$ -
Liability Derivatives			
Crude oil price swaps and natural gas basis swaps -			
Current portion	Liabilities from Price Risk		
	Management Activities	$ 30	$ 57
Noncurrent portion	Other Liabilities	$ -	$ 9
Foreign currency and interest rate swap -			
Noncurrent portion	Other Liabilities	$ 53	$ 49

Credit Risk. Notional contract amounts are used to express the magnitude of commodity price, foreign currency and interest rate swap agreements. The amounts potentially subject to credit risk, in the event of nonperformance by the counterparties, are equal to the fair value of such contracts (see Note 12). EOG evaluates its exposure to significant counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG requires collateral, parent guarantees or letters of credit to minimize credit risk. At December 31, 2010, EOG's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales include one receivable balance which constituted 13% of the total balance. These receivables were due from a midstream company. The related amounts were collected during early 2011. At December 31, 2009, a crude oil marketing company's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales accounted for 12% of the total balance. The related amounts were collected during early 2010. In 2010 and 2009, natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago and natural gas from EOG's China operations was sold to Petrochina Company Limited.

All of EOG's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDA) with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDAs may also provide that as a result of certain circumstances, including certain events that cause EOG's credit ratings to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDA to be settled immediately. See Note 12 for the aggregate fair value of all derivative instruments with credit-risk related contingent features that are in a net liability position at December 31, 2010 and 2009. EOG had no collateral posted at both December 31, 2010 and 2009.

At December 31, 2010 and 2009, EOG had an allowance for doubtful accounts of $14 million and $13 million, respectively, of which $11 million as of each year-end were associated with bankruptcies in December 2001.

Substantially all of EOG's accounts receivable at December 31, 2010 and 2009 resulted from hydrocarbon sales and/or joint interest billings to third-party companies, including foreign state-owned entities in the oil and gas industry. This concentration of customers and joint interest owners may impact EOG's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral or other credit enhancements from a customer or joint interest owner, EOG typically analyzes the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. During the three-year period ended December 31, 2010, credit losses incurred on receivables by EOG have been immaterial.

12. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the Consolidated Balance Sheets. Effective January 1, 2008, EOG adopted the provisions of the Fair Value Measurements and Disclosures Topic of the ASC (ASC Topic 820) for its financial assets and liabilities. ASC Topic 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. To increase consistency and comparability in fair value measurements and related disclosures, ASC Topic 820 establishes a fair value hierarchy that prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. ASC Topic 820 requires that an entity give consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value. EOG adopted the provisions of ASC Topic 820 relating to nonfinancial assets and liabilities effective January 1, 2009.

The following table provides fair value measurement information within the fair value hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at December 31, 2010 and 2009 (in millions):

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
At December 31, 2010				
Financial Assets:				
Natural Gas Price Swaps	$-	$62	$ -	$62
Natural Gas Swaptions	-	6	-	6
Interest Rate Swaps	-	2	-	2
Financial Liabilities:				
Crude Oil Price Swaps and Natural Gas Basis Swaps	$-	$29	$ -	$29
Foreign Currency Rate Swap	-	55	-	55
Contingent Consideration (see Note 17)	-	-	14	14
At December 31, 2009				

Financial Assets:				
Natural Gas Collars, Price Swaps and Basis Swaps	$-	$21	$ -	$21
Financial Liabilities:				
Natural Gas Collars, Price Swaps and Basis Swaps	$-	$37	$ -	$37
Foreign Currency Rate Swap	-	49	-	49
Contingent Consideration (see Note 17)	-	-	35	35

The estimated fair value of crude oil financial price swap contracts, natural gas financial collar, price swap and basis swap contracts, natural gas swaption contracts and interest rate swap contracts (see Note 11) was based upon forward commodity price and interest rate curves based on quoted market prices. The estimated fair value of the foreign currency rate swap was based upon forward currency rates.

In connection with the acquisition of certain unproved acreage in Nacogdoches County, Texas, during the fourth quarter of 2009 and the first quarter of 2010, EOG could be required to make an additional one-time supplemental cash payment to the sellers contingent upon future natural gas prices over a five year period (see Note 17). The fair value of the contingent consideration was estimated using present value techniques based upon an assessment of the probability that EOG would be required to make such future payment. Level 3 inputs used in such assessment include EOG's internal estimates of future natural gas prices and an appropriate risk-adjusted discount rate.

The following table presents the reconciliation of the beginning and ending fair value of EOG's contingent consideration liability measured using significant unobservable inputs (Level 3) during the year ended December 31, 2010 (in millions):

	Year Ended December 31, 2010
Fair Value at Beginning of Period	$35
Additions (see Note 17)	3
Change in Fair Value Included in Earnings (1)	(24)
Fair Value at End of Period	$14

(1) Reflected as a reduction of depreciation, depletion and amortization.

In connection with an exchange of certain natural gas properties during the fourth quarter of 2009 (see Note 17), EOG recorded oil and gas properties with a fair value of $545 million. Significant Level 3 inputs used in determining the fair value of the properties received in the exchange transaction included EOG's estimate of future natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 14.

Proved oil and gas properties and other property, plant and equipment with a carrying amount of $1,013 million were written down to their fair value of $487 million, resulting in pretax impairment charges of $418 million in Canada (see Note 17), $107 million in the United States and $1 million in Trinidad for the year ended December 31, 2010. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. In connection with the $280 million impairment of shallow natural gas assets sold in Canada during the fourth quarter of 2010, EOG utilized accepted bids adjusted for estimates of customary closing adjustments less selling costs as the basis for determining fair value. See Note 13.

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13. Accounting for Certain Long-Lived Assets

EOG reviews its proved oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. During 2010, 2009 and 2008, such reviews indicated that unamortized capitalized costs of certain properties were higher than their expected undiscounted future cash flows due primarily to downward reserve revisions, drilling of marginal or uneconomic wells, or development dry holes in certain producing fields. As a result, EOG recorded pretax charges of $107 million, $90 million and $58 million in the United States operating segment during 2010, 2009 and 2008, respectively, $418 million, $4 million and $2 million in the Canada operating segment during 2010, 2009 and 2008, respectively, and $1 million in the Trinidad operating segment during 2010. Additionally, during 2008, EOG recorded pretax charges of $20 million and $6 million in the Trinidad and United Kingdom operating segments, respectively. The pretax charges are included in Impairments on the Consolidated Statements of Income and Comprehensive Income. The carrying values for assets determined to be impaired were adjusted to estimated fair values based on projected future net cash flows discounted using an appropriate risk-adjusted discount rate or, in the case of certain assets held for sale, accepted bids less estimated selling costs. Amortization of unproved oil and gas property costs, including amortization of capitalized interest, was $217 million, $212 million and $107 million for 2010, 2009 and 2008, respectively.

14. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of short-term and long-term legal obligations associated with the retirement of property, plant and equipment for the years ended December 31, 2010 and 2009 (in thousands):

	2010	2009
Carrying Amount at Beginning of Period	$456,484	$368,159
Liabilities Incurred	39,480	70,932
Liabilities Settled	(30,763)	(29,920)
Accretion	25,456	24,218
Revisions (1)	1,640	10,564
Foreign Currency Translations	5,991	12,531
Carrying Amount at End of Period	$498,288	$456,484
Current Portion	$32,005	$29,630
Noncurrent Portion	$466,283	$426,854

(1) Revisions to asset retirement obligations primarily reflect changes in abandonment cost estimates.

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

15. Investment in Caribbean Nitrogen Company Limited and Nitrogen (2000) Unlimited

EOG, through certain wholly-owned subsidiaries, owns equity interests in two Trinidadian companies: Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000). At December 31, 2010, EOG's equity interests in CNCL and N2000 were 12% and 10%, respectively.

At December 31, 2010, the investment in CNCL was $21 million. CNCL commenced ammonia production in June 2002. At December 31, 2010, CNCL had a long-term debt balance of $46 million, which is non-recourse to CNCL's shareholders. EOG would be liable for its share of any post-completion deficiency funds, loans to fund the costs of operation, payment of principal and interest to the principal creditor and other cash deficiencies of CNCL up to $15 million, approximately $2 million of which is net to EOG's interest. Since inception, there have been no such borrowings by CNCL. The shareholders' agreement governing CNCL requires the consent of the holders of 90% or more of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOG is able to exercise significant influence over the operating and financial policies of CNCL and, therefore, it accounts for the investment using the equity method. During 2010, EOG recognized equity income of $5 million and received cash dividends of $6 million from CNCL.

At December 31, 2010, the investment in N2000 was $18 million. N2000 commenced ammonia production in August 2004. At December 31, 2010, N2000 had a long-term debt balance of $59 million, which is non-recourse to N2000's shareholders. EOG would be liable for its share of any post-completion deficiency funds, loans to fund the costs of operation, payment of principal and interest to the principal creditor and other cash deficiencies of N2000 up to $15 million, approximately $2 million of which is net to EOG's interest. Since inception, there have been no such borrowings by N2000. The shareholders' agreement governing N2000 requires the consent of the holders of 100% of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOG is able to exercise significant influence over the operating and financial policies of N2000 and, therefore, it accounts for the investment using the equity method. During 2010, EOG recognized equity income of $8 million and received cash dividends of $10 million from N2000.

16. Suspended Well Costs

EOG's net changes in capitalized exploratory well costs for the years ended December 31, 2010, 2009 and 2008 are presented below (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Balance at January 1	$118,459	$85,255	$148,881
Additions Pending the Determination of Proved Reserves	94,090	75,362	96,698
Reclassifications to Proved Properties	(93,333)	(40,614)	(120,110)
Charged to Dry Hole Costs	(20,267)	(11,223)	(22,116)
Foreign Currency Translations	852	9,679	(18,098)
Balance at December 31	$99,801	$118,459	$85,255

The following table provides an aging of capitalized exploratory well costs at December 31, 2010, 2009 and 2008 (in thousands, except well count):

	Year Ended December 31,		
	2010	2009	2008
Capitalized exploratory well costs that have been capitalized for a period less than one year	$43,408	$51,141	$31,784
Capitalized exploratory well costs that have been capitalized for a period greater than one year	56,393 (1)	67,318 (2)	53,471 (3)
Total	$99,801	$118,459	$85,255
Number of exploratory wells that have been capitalized for a period greater than one year	4	4	3

(1) Consists of costs related to an outside operated, offshore Central North Sea project in the United Kingdom (U.K.) ($21 million), an East Irish Sea project in the U.K. ($9 million), a project in the Sichuan Basin, Sichuan Province, China ($20 million), and a remaining shale project in British Columbia, Canada (B.C.) ($6 million). In the Central North Sea project, the operator and partners are currently negotiating processing and transportation terms with

export infrastructure owners. The operator expects to submit 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 by the end of 2011. In the East Irish Sea project, EOG has submitted its field development plan to the DECC during the first quarter of 2011 with regulatory approval expected by the end of 2011. The evaluation of the Sichuan Basin project is expected to be completed during the first half of 2011. In the remaining B.C. shale project, EOG intends to drill additional wells beginning in 2011 to develop and further evaluate the project. Well completion activities are expected to commence in 2013.

(2) Consists of costs related to three shale projects in B.C. ($45 million) and an outside operated, offshore Central North Sea project in the U.K. ($22 million).

(3) Costs related to two shale projects in B.C. ($35 million) and an outside operated, offshore Central North Sea project in the U.K. ($19 million).

17. Acquisitions and Divestitures

In the fourth quarter of 2010, EOG completed the sales of certain of its Canadian shallow natural gas assets in three separate transactions. EOG had previously announced its plans to market its Canadian shallow natural gas assets and began marketing such assets in July 2010. Proceeds from the sales were approximately $344 million. The purchase price is subject to customary adjustments under each respective sales agreement. In 2010, EOG recorded a pretax impairment of $280 million to adjust the shallow natural gas assets sold to estimated fair value less estimated cost to sell. In addition, EOG received proceeds of approximately $329 million from the sale in 2010 of non-core producing properties and acreage, primarily in the Rocky Mountain area, Texas, and Pennsylvania.

During the second quarter of 2010, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOGRC), agreed to acquire all of the outstanding common stock of Galveston LNG Inc., a Calgary-based corporation which, through its wholly-owned subsidiary, Kitimat LNG Inc. and affiliates, owns 49 percent of the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia. In addition, Galveston LNG Inc. also owns a 24.5 percent interest in the proposed Pacific Trail Pipelines (PTP) originating at Summit Lake, British Columbia. The pipeline is intended to link Western Canada's natural gas producing regions to the Kitimat LNG terminal. An affiliate of Apache Corporation owns 51 percent of the planned Kitimat LNG terminal and a 25.5 percent interest in PTP and will be the operator of the Kitimat LNG terminal. During the fourth quarter of 2010, upon the achievement of certain commercial and regulatory milestones, EOGRC paid $210 million to complete the acquisition of Galveston LNG Inc. In connection with the acquisition, EOG recorded intangible assets related to certain leases, permits and other contracts. Such intangible assets are included in Other Assets on the Consolidated Balance Sheets. During the first quarter of 2011, EOGRC entered into an agreement to purchase an additional 24.5 percent interest in PTP for $24.5 million (subject to customary closing conditions). A portion of the purchase price ($14.7 million) will be paid at closing with the remaining amount ($9.8 million) to be paid contingent on the decision to proceed with the construction of the Kitimat LNG terminal. Subsequent to closing, EOGRC's ownership interest will be 49 percent. An affiliate of Apache Corporation entered into an agreement to purchase the remaining 25.5 percent interest in PTP, which will increase its ownership interest to 51 percent of the proposed project.

In December 2009, EOG and a third party entered into an asset exchange agreement whereby the two parties exchanged certain natural gas related properties in the Rocky Mountain area. In accordance with the provisions of ASC Topic 805 (Business Combinations), EOG realized a pretax gain of $390 million on the exchange to reflect the excess of the fair value of the properties received over the book basis of the properties given up in the transaction (see Note 12).

In November 2009, EOG entered into an agreement to sell its crude oil and natural gas related assets located in California for consideration of $202 million subject to customary adjustments under the agreement. The assets sold accounted for less than 1% of EOG's total 2009 production. The transaction closed on December 10, 2009. EOG realized a pretax gain in 2009 of approximately $146 million on the sale.

In October 2009, EOG entered into an agreement to acquire unproved acreage located in Nacogdoches County, Texas, within the Haynesville and Bossier Shale formations (Haynesville Assets). EOG acquired a portion of the unproved acreage at the principal and supplemental closings held in October 2009 and December 2009, respectively. The acquisition agreement provides for an additional one-time supplemental cash payment to the sellers of the Haynesville Assets that is contingent on the satisfaction of certain conditions (within a five-year period beginning on the principal closing date) set forth in the acquisition agreement with respect to future natural gas prices. EOG estimated the fair value of the contingent consideration as of the acquisition dates in accordance with the provisions of the ASC Topic 805 and has included such amount in Other Liabilities on the Consolidated Balance Sheets. In accordance with the acquisition agreement, EOG acquired additional Haynesville Assets at a final closing which occurred in the first quarter of 2010. The aggregate consideration recorded in 2009 and 2010 for the acquisition of the Haynesville Assets was $134 million and $18 million, respectively, including the fair value of contingent consideration estimated at $35 million and $3 million, respectively, at the dates of acquisition (see Note 12).

During the third quarter of 2009, EOG completed three transactions to acquire certain crude oil and natural gas properties and related assets located in Montague and Cooke Counties, Texas (Barnett Shale Combo Assets). The Barnett Shale Combo Assets consist of proved developed and undeveloped reserves and unproved acreage. The aggregate purchase price of the transactions totaled $197 million, consisting of cash consideration of $107 million and 1,450,000 shares of EOG common stock valued at $89.6 million on the closing date of the applicable transaction.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS

(In Thousands, Except Per Share Data Unless Otherwise Indicated)
(Unaudited)

Oil and Gas Producing Activities

In December 2008, the United States Securities and Exchange Commission (SEC) released a final rule, "Modernization of Oil and Gas Reporting," which amended the oil and gas reporting requirements effective January 1, 2010. The key revisions include:

- using a 12-month average price to determine reserves;
- including nontraditional resources in reserves if they are intended to be upgraded to synthetic oil and gas;
- the ability to use reliable technologies to determine and estimate reserves;
- permitting the optional disclosure of probable and possible reserves;
- reporting the independence and qualifications of the reserve preparer or auditor and filing a report as an exhibit when a third party is relied upon to prepare reserve estimates or conduct reserve audits; and
- disclosing the development of any proved undeveloped reserves, including the total quantity of proved undeveloped reserves at year-end, material changes to proved undeveloped reserves during the year, investments and progress toward the development of proved undeveloped reserves and an explanation of the reasons why material concentrations of proved undeveloped reserves have remained undeveloped for five years or more after disclosure as proved undeveloped reserves

In January 2010, the Financial Accounting Standards Board (FASB) issued FASB Accounting Standards Update (ASU) No. 2010-03, "Oil and Gas Reserve Estimations and Disclosures" (ASU No. 2010-03). This update aligns the current oil and gas reserve estimation and disclosure requirements of the Extractive Industries - Oil and Gas topic of the FASB Accounting Standards Codification (ASC Topic 932) with the changes required by the SEC final rule, "Modernization of Oil and Gas Reporting." ASU No. 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009.

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil, natural gas liquids and natural gas reserves is complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. 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. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. See ITEM 1A. Risk Factors.

Proved reserves represent estimated quantities of crude oil, natural gas liquids and natural gas that geoscience and engineering data can estimate, with reasonable certainty, to be economically producible from a given day forward from known reservoirs under economic conditions, operating methods and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Proved developed reserves are proved reserves expected to be recovered under operating methods being utilized at the time the estimates were made, through wells and equipment in place or if the cost of any required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

In making estimates of proved undeveloped reserves, EOG's technical staff, including engineers and geoscientists, perform detailed technical analysis of each potential drilling location within its entire inventory of prospects. In making a determination as to which of these locations would penetrate undrilled portions of the formation that can be judged, with reasonable certainty, to be continuous and contain economically producible oil and gas, studies are conducted using numerous data elements and analysis techniques. EOG technical staff estimates the hydrocarbons in place, by mapping the entirety of the play in question using seismic techniques, typically employing two-dimensional and three-dimensional data. This analysis is integrated with other static data including, but not limited to, core analysis, mechanical properties of the formation, thermal maturity indicators, and well logs of existing penetrations. Highly specialized equipment is utilized to prepare rock samples in assessing microstructures which contribute to porosity and permeability.

Analysis of dynamic data is then incorporated to arrive at the estimated fractional recovery of hydrocarbons in place. Data and analysis techniques employed include, but are not limited to, well testing, static bottom hole pressure, flowing bottom hole pressure, historical production trends using extant completion techniques (typically from vertical wells), pressure transient analysis and rate transient analysis. Application of proprietary rate transient analysis techniques allow for quantification of estimates of contribution to production from both fractures and rock matrices.

The impact of optimal completion techniques is a key factor in determining if prospective locations are reasonably certain of being economically producible. EOG's technical staff estimates recovery improvement that might be achieved when employing horizontal wells with multi-stage fracture stimulation. In the early stages of development, EOG determines the optimal length of the horizontal lateral and multi-stage fracture stimulation using the aforementioned analysis techniques along with pilot drilling programs.

The process of analyzing static and dynamic data, well completion optimization and the results of early development provides the appropriate level of certainty as well as support for the economic producibilty of the plays in which proved undeveloped reserves are reflected. EOG has found that this approach has been proven effective based on successful application in analogous reservoirs in resource plays.

EOG has formulated development plans for all locations related to its proved undeveloped reserves. In these plans, substantially all such locations will be developed within the next five years. Those few locations developed in year six or later are located in areas in which EOG has a demonstrated track record of continuous development activity that exceeds the length of the current development plan.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices, production volumes and the length, both vertical and horizontal, of wells. Canadian reserves, as presented on a net basis, assume prices and legislated future royalty rates and EOG's estimate of future production volumes. Similarly, certain of EOG's Trinidad reserves are held under production sharing contracts where EOG's interest varies with prices and production volumes. Trinidad reserves, as presented on a net basis, assume prices in existence at the time the estimates were made and EOG's estimate of future production volumes. Future fluctuations in prices, production rates or changes in political or regulatory environments could cause EOG's share of future production from Canadian and Trinidadian reserves to be materially different from that presented.

Estimates of proved reserves at December 31, 2010, 2009 and 2008 were based on studies performed by the engineering staff of EOG. The Engineering and Acquisitions Department is directly responsible for EOG's reserve evaluation process and consists of seven professionals, all of whom hold, at a minimum, bachelor's degrees in engineering and three are Registered Professional Engineers. The Manager, Engineering and Acquisitions is the manager of this department and is the primary technical person responsible for this process. The Manager, Engineering and Acquisitions holds a Bachelor of Science degree in Petroleum Engineering, has 25 years of experience in reserve evaluations and is a Registered Professional Engineer in the State of Texas.

EOG's reserves estimation process is a collaborative effort coordinated by the Engineering and Acquisitions Department in compliance with EOG's internal controls for such process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including crude oil, natural gas liquids and natural gas prices, production costs, future capital expenditures and EOG's net ownership percentages are obtained from other departments within EOG. EOG's Internal Audit Department conducts testing with respect to such non-technical inputs. Additionally, EOG engages DeGolyer and MacNaughton (D&M), independent petroleum consultants, to perform independent reserves evaluation of select EOG properties of not less than 75 percent of proved reserves. EOG's Board of Directors requires that D&M's and EOG's reserve quantities for the properties evaluated by D&M vary by no more than 5 percent in the aggregate. Once completed, EOG's year-end reserves are presented to senior management, including the Chairman of the Board and Chief Executive Officer; the Senior Executive Vice President, Exploration; the Senior Executive Vice President, Operations; and the Vice President and Chief Financial Officer for approval.

Opinions by D&M for the years ended December 31, 2010, 2009 and 2008 covered producing areas containing 77%, 81% and 79%, respectively, of proved reserves of EOG on a net-equivalent-barrel-of-oil basis. D&M's opinions indicate that the estimates of proved reserves prepared by EOG's Engineering and Acquisitions Department for the properties reviewed by D&M, when compared in total on a net-equivalent-barrel-of-oil basis, do not differ materially from the estimates prepared by D&M. Such estimates by D&M in the aggregate varied by not more than 5% from those prepared by the Engineering and Acquisitions Department of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG. The report of D&M dated February 18, 2011, which contains further discussion of the reserve estimates and evaluations prepared by D&M, as well as the qualifications of D&M's technical person primarily responsible for overseeing such estimates and evaluations, is attached as Exhibit 23.2 to this Annual Report on Form 10-K and incorporated herein by reference.

No major discovery or other favorable or adverse event subsequent to December 31, 2010 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

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EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables set forth EOG's net proved and proved developed reserves at December 31 for each of the four years in the period ended December 31, 2010, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2010, as estimated by the Engineering and Acquisitions Department of EOG:

NET PROVED AND PROVED DEVELOPED RESERVE SUMMARY

	United States	Canada	Trinidad	Other International (1)	Total
NET PROVED RESERVES					
Crude Oil (MBbl) (2)					
Net proved reserves at December 31, 2007	96,108	9,394	8,900	47	114,449
Revisions of previous estimates	1,258	(1,772)	403	(20)	(131)
Purchases in place	6	-	184	58	248
Extensions, discoveries and other additions	50,972	858	-	-	51,830
Sales in place	(495)	-	-	-	(495)
Production	(14,487)	(982)	(1,161)	(20)	(16,650)
Net proved reserves at December 31, 2008	133,362	7,498	8,326	65	149,251
Revisions of previous estimates	4,402	(183)	(1,760)	17	2,476
Purchases in place	15,666	-	-	-	15,666
Extensions, discoveries and other additions	58,258	19,783	-	-	78,041
Sales in place	(5,742)	(20)	-	-	(5,762)
Production	(17,494)	(1,492)	(1,123)	(24)	(20,133)
Net proved reserves at December 31, 2009	188,452	25,586	5,443	58	219,539
Revisions of previous estimates	(8,313)	(104)	(754)	20	(9,151)
Purchases in place	13	-	-	-	13
Extensions, discoveries and other additions	199,479	3,198	1,751	48	204,476
Sales in place	(1,082)	(589)	-	-	(1,671)
Production	(23,092)	(2,455)	(1,709)	(28)	(27,284)
Net proved reserves at December 31, 2010	355,457	25,636	4,731	98	385,922
Natural Gas Liquids (MBbl) (2)					
Net proves reserves at December 31, 2007	63,913	972	-	-	64,885
Revisions of previous estimates	(2,850)	2,626	-	-	(224)
Purchases in place	-	-	-	-	-
Extensions, discoveries and other additions	16,905	60	-	-	16,965
Sales in place	-	-	-	-	-
Production	(5,484)	(361)	-	-	(5,845)

Net proved reserves at December 31, 2008	72,484	3,297	-	-	75,781
Revisions of previous estimates	6,109	(926)	-	-	5,183
Purchases in place	5,801	-	-	-	5,801
Extensions, discoveries and other additions	18,546	24	-	-	18,570
Sales in place	(3,231)	(30)	-	-	(3,261)
Production	(8,220)	(393)	-	-	(8,613)
Net proved reserves at December 31, 2009	91,489	1,972	-	-	93,461
Revisions of previous estimates	27,490	(196)	-	-	27,294
Purchases in place	-	-	-	-	-
Extensions, discoveries and other additions	42,221	21	-	-	42,242
Sales in place	(2)	(6)	-	-	(8)
Production	(10,764)	(316)	-	-	(11,080)
Net proved reserves at December 31, 2010	150,434	1,475	-	-	151,909

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Canada	Trinidad	Other International (1)	Total
Natural Gas (Bcf) (3)					
Net proved reserves at December 31, 2007	4,220.1	1,219.8	1,216.3	12.9	6,669.1
Revisions of previous estimates	(110.3)	22.9	62.2	(4.2)	(29.4)
Purchases in place	31.0	15.0	-	12.2	58.2
Extensions, discoveries and other additions	1,384.4	60.6	-	-	1,445.0
Sales in place	(200.2)	-	-	-	(200.2)
Production	(436.0)	(81.1)	(80.4)	(6.0)	(603.5)
Net proved reserves at December 31, 2008	4,889.0	1,237.2	1,198.1	14.9	7,339.2
Revisions of previous estimates	(378.0)	(447.2)	(104.9)	3.0	(927.1)
Purchases in place	450.8	-	-	-	450.8
Extensions, discoveries and other additions	1,925.0	846.5	-	-	2,771.5
Sales in place	(114.4)	(5.1)	-	-	(119.5)
Production	(422.3)	(81.9)	(107.4)	(5.2)	(616.8)
Net proved reserves at December 31, 2009	6,350.1	1,549.5	985.8	12.7	8,898.1
Revisions of previous estimates	(222.7)	(29.9)	(88.6)	1.9	(339.3)
Purchases in place	-	-	-	-	-
Extensions, discoveries and other additions	821.3	3.4	63.0	7.9	895.6
Sales in place	(34.6)	(316.2)	-	-	(350.8)
Production	(422.6)	(73.0)	(132.6)	(5.2)	(633.4)
Net proved reserves at December 31, 2010	6,491.5	1,133.8	827.6	17.3	8,470.2
Oil Equivalents (MBoe) (2)					
Net proved reserves at December 31, 2007	863,363	213,670	211,622	2,203	1,290,858
Revisions of previous estimates	(19,971)	4,678	10,773	(712)	(5,232)
Purchases in place	5,180	2,500	184	2,084	9,948
Extensions, discoveries and other additions	298,601	11,013	-	-	309,614
Sales in place	(33,870)	-	-	-	(33,870)
Production	(92,632)	(14,859)	(14,566)	(1,027)	(123,084)
Net proved reserves at December 31, 2008	1,020,671	217,002	208,013	2,548	1,448,234
Revisions of previous estimates	(52,487)	(75,638)	(19,250)	515	(146,860)
Purchases in place	96,605	-	-	-	96,605
Extensions, discoveries and other additions	397,642	160,882	-	-	558,524
Sales in place	(28,032)	(898)	-	-	(28,930)

Production	(96,107)	(15,540)	(19,016)	(891)	(131,554)
Net proved reserves at December 31, 2009	1,338,292	285,808	169,747	2,172	1,796,019
Revisions of previous estimates	(17,945)	(5,288)	(15,513)	342	(38,404)
Purchases in place	14	-	-	-	14
Extensions, discoveries and other additions	378,582	3,789	12,250	1,363	395,984
Sales in place	(6,860)	(53,288)	-	-	(60,148)
Production	(104,277)	(14,937)	(23,815)	(901)	(143,930)
Net proved reserves at December 31, 2010	1,587,806	216,084	142,669	2,976	1,949,535

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(1) Includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

(2) Thousand barrels or thousand barrels of oil equivalent, as applicable; includes crude oil and condensate and natural gas liquids. Crude oil equivalents are determined using the ratio of 1.0 barrel of crude oil and condensate or natural gas liquids to 6.0 thousand cubic feet of natural gas.

(3) Billion cubic feet.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2010, EOG added 396 million barrels of oil equivalent (MMBoe) of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Eagle Ford, Bakken, Barnett Combo and Haynesville shale plays. Approximately 62% of the 2010 reserve additions were crude oil and condensate and natural gas liquids and over 95% were in the United States. Sales in place of 60 MMBoe were primarily related to the Canadian shallow natural gas assets and certain producing natural gas assets in East Texas. Revisions of previous estimates of negative 38 MMBoe for 2010 included a positive revision of 28 MMBoe primarily due to an increase in the average natural gas price used in the December 31, 2010 reserves estimation as compared to the price used in the prior year estimate. Revisions other than price resulted from negative performance revisions for certain natural gas properties in the United States, Canada and Trinidad and the removal of proved undeveloped natural gas drilling locations from the five-year drilling plan to focus on crude oil and liquids-rich drilling as part of EOG's overall strategy.

During 2009, EOG added 558 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Haynesville, Horn River, Barnett, Bakken and Marcellus shale plays. Approximately 82% of the 2009 reserve additions were natural gas. EOG's revisions of previous estimates for 2009 of negative 147 MMBoe included negative revisions of approximately 131 MMBoe, which were primarily due to the decrease in the average natural gas price used in the December 31, 2009 reserves estimation as compared to the price used in the prior year estimate. Purchases in place include the reserves acquired in the Rocky Mountain property exchange and the acquisition of certain Barnett Shale Combo Assets in Montague and Cooke Counties, Texas. Sales in place primarily include reserves from the properties relinquished in the Rocky Mountain property exchange and from the California asset sale. See Note 17.

During 2008, EOG added 310 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Barnett Shale play, the Uintah Basin, the Williston Basin and the South Texas area. Approximately 78% of the 2008 reserve additions were natural gas. Sales in place of 34 MMBoe were primarily due to the sale of shallow natural gas assets in the Appalachian Basin. Revisions of previous estimates of negative 5 MMBoe included a negative revision of 12 MMBoe due to price changes and a positive performance revision of 7 MMBoe. Purchases in place were 10 MMBoe.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Canada	Trinidad	Other International (1)	Total
NET PROVED DEVELOPED RESERVES					
Liquids (MBbl) (2)					
December 31, 2007	119,949	10,193	7,222	47	137,411
December 31, 2008	159,607	10,416	6,756	65	176,844
December 31, 2009	189,322	10,831	3,966	58	204,177
December 31, 2010	253,308	12,758	3,853	98	270,017
Natural Gas (Bcf) (3)					
December 31, 2007	3,141.8	1,079.1	916.7	12.9	5,150.5
December 31, 2008	3,544.7	1,103.7	889.0	14.9	5,552.3
December 31, 2009	3,330.1	681.0	609.4	12.7	4,633.2
December 31, 2010	3,519.7	401.6	519.2	17.3	4,457.8
Oil Equivalents (MBoe) (2)					
December 31, 2007	643,577	190,049	160,001	2,203	995,830
December 31, 2008	750,389	194,360	154,939	2,548	1,102,236
December 31, 2009	744,339	124,323	105,540	2,172	976,374
December 31, 2010	839,928	79,701	90,382	2,976	1,012,987
NET PROVED UNDEVELOPED RESERVES					
Liquids (MBbl) (2)					
December 31, 2007	40,072	173	1,678	-	41,923
December 31, 2008	46,239	379	1,570	-	48,188
December 31, 2009	90,619	16,727	1,477	-	108,823
December 31, 2010	252,583	14,352	879	-	267,814
Natural Gas (Bcf) (3)					
December 31, 2007	1,078.3	140.7	299.6	-	1,518.6
December 31, 2008	1,344.3	133.6	309.0	-	1,786.9
December 31, 2009	3,020.0	868.5	376.4	-	4,264.9
December 31, 2010	2,971.7	732.2	308.5	-	4,012.4
Oil Equivalents (MBoe) (2)					
December 31, 2007	219,786	23,621	51,621	-	295,028
December 31, 2008	270,282	22,642	53,074	-	345,998
December 31, 2009	593,953	161,486	64,207	-	819,646
December 31, 2010	747,878	136,383	52,287	-	936,548

(1) Includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

(2) Thousand barrels or thousand barrels of oil equivalent, as applicable; includes crude oil and condensate and natural gas liquids. Crude oil equivalents are determined using the ratio of 1.0 barrel of crude oil and condensate or

natural gas liquids to 6.0 thousand cubic feet of natural gas.

(3) Billion cubic feet.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the twelve-month period ended December 31, 2010, total proved undeveloped reserves (PUDs) increased by 117 MMBoe to 937 MMBoe. EOG added approximately 37 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs (see discussion of technology employed on page F-35 of this Annual Report on Form 10-K), EOG added 218 MMBoe. The proved undeveloped reserve additions were primarily in the Eagle Ford, Bakken, Barnett Combo and Haynesville shale plays, and nearly 73% of the additions were crude oil and condensate and natural gas liquids. During 2010, EOG drilled and transferred 118 MMBoe of PUDs to proved developed reserves at a total capital cost of $1,280 million. Revisions of PUDs totaled negative 12 MMBoe, primarily due to removal of certain natural gas PUDs from the five-year drilling plan. During 2010, EOG sold 8 MMBoe of PUDs.

For the twelve-month period ended December 31, 2009, total PUDs increased by 474 MMBoe to 820 MMBoe. Based on the definition of PUDs and its applicability to large resource plays (see discussion of technology employed on page F-35), EOG added 445 MMBoe of PUDs, primarily in the Haynesville, Horn River, Barnett Combo and Marcellus shale plays. Purchases in place included 70 MMBoe of PUDs from the Rocky Mountain property exchange and the acquisition of Barnett Shale Combo assets (see Note 17 to Consolidated Financial Statements). During 2009, EOG drilled and transferred approximately 29 MMBoe of PUDs to proved developed reserves at a total capital cost of $280 million. Revisions of PUDs totaled negative 9 MMBoe.

EOG does not have a material amount of reserves that have remained undeveloped for five years or more.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to EOG's crude oil and natural gas producing activities at December 31, 2010 and 2009:

	2010	2009
Proved properties	$27,693,700	$23,097,568
Unproved properties	1,570,109	1,516,743
Total	29,263,809	24,614,311
Accumulated depreciation, depletion and amortization	(11,859,870)	(9,479,525)
Net capitalized costs	$17,403,939	$15,134,786

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities. The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in ASC Topic 932.

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property.

Exploration costs include additions to exploratory wells, including those in progress, and exploration expenses.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Development costs include additions to production facilities and equipment and additions to development wells, including those in progress.

The following tables set forth costs incurred related to EOG's oil and gas activities for the years ended December 31, 2010, 2009 and 2008:

	United States	Canada	Trinidad	Other International (1)	Total
2010					
Acquisition Costs of Properties					
Unproved (2)	$403,509	$13,956	$-	$(107)	$417,358
Proved	-	-	-	-	-
Subtotal	403,509	13,956	-	(107)	417,358
Exploration Costs	454,379	38,604	23,386	86,784	603,153
Development Costs (3)	3,892,403	417,176	114,986	13,429	4,437,994
Total	$4,750,291	$469,736	$138,372	$100,106	$5,458,505
2009					
Acquisition Costs of Properties					
Unproved (2)	$648,331	$17,806	$800	$(311)	$666,626
Proved (4)	464,362	(33)	-	-	464,329
Subtotal	1,112,693	17,773	800	(311)	1,130,955
Exploration Costs	473,489	51,164	14,263	71,872	610,788
Development Costs (5)	1,898,859	237,613	27,369	1,914	2,165,755
Total	$3,485,041	$306,550	$42,432	$73,475	$3,907,498
2008					
Acquisition Costs of Properties					
Unproved	$376,017	$141,080	$313	$3,438	$520,848
Proved	69,612	14,071	14,836	10,301	108,820
Subtotal	445,629	155,151	15,149	13,739	629,668
Exploration Costs	550,725	95,647	6,638	16,693	669,703
Development Costs (6)	3,405,627	281,480	99,384	7,166	3,793,657
Total	$4,401,981	$532,278	$121,171	$37,598	$5,093,028

(1) Other International primarily consists of EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

(2) Includes non-cash contingent consideration, with a fair value of $3 million and $35 million for 2010 and 2009, respectively, related to the acquisition of the Haynesville Assets. See Note 17 to Consolidated Financial Statements.

(3) Includes Asset Retirement Costs of $71 million, $2 million, $(3) million and $2 million for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

(4) Includes non-cash acquisition costs of $353 million related to a property exchange transaction in the Rocky Mountain area.

(5) Includes Asset Retirement Costs of $60 million, $18 million, $6 million and zero for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

(6) Includes Asset Retirement Costs of $107 million, $38 million, $29 million and $7 million for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of Operations for Oil and Gas Producing Activities (1). The following tables set forth results of operations for oil and gas producing activities for the years ended December 31, 2010, 2009 and 2008:

	United States	Canada	Trinidad	Other International (2)	Total
2010					
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$3,928,240	$477,416	$447,852	$ 27,707	$4,881,215
Other	19,886	(31)	3,696	-	23,551
Total	3,948,126	477,385	451,548	27,707	4,904,766
Exploration Costs	156,252	17,597	2,277	11,255	187,381
Dry Hole Costs	30,927	14,875	5,000	21,684	72,486
Transportation Costs	372,466	9,892	1,348	1,483	385,189
Production Costs	763,769	174,667	51,125	8,504	998,065
Impairments	271,466	451,703	1,465	418	725,052
Depreciation, Depletion and Amortization	1,430,408	314,663	70,553	15,399	1,831,023
Income (Loss) Before Income Taxes	922,838	(506,012)	319,780	(31,036)	705,570
Income Tax Provision (Benefit)	375,855	(151,315)	140,413	(14,245)	350,708
Results of Operations	$546,983	$(354,697)	$179,367	$ (16,791)	$354,862
2009					
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$2,732,088	$413,910	$229,649	$ 23,826	$3,399,473
Other	9,692	(15)	3,500	-	13,177
Total	2,741,780	413,895	233,149	23,826	3,412,650
Exploration Costs	137,696	18,675	5,107	8,114	169,592
Dry Hole Costs	39,570	1,461	-	10,212	51,243
Transportation Costs	270,940	9,317	1,141	1,931	283,329
Production Costs	556,236	145,292	27,616	9,452	738,596
Impairments	272,195	32,996	-	641	305,832
Depreciation, Depletion and Amortization	1,188,243	210,509	46,608	7,966	1,453,326
Income (Loss) Before Income Taxes	276,900	(4,355)	152,677	(14,490)	410,732
Income Tax Provision (Benefit)	106,537	(1,276)	58,681	(6,067)	157,875
Results of Operations	$170,363	$(3,079)	$93,996	$ (8,423)	$252,857
2008					
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$5,049,783	$727,707	$393,062	$ 51,432	$6,221,984
Other	18,193	1,002	45	-	19,240
Total	5,067,976	728,709	393,107	51,432	6,241,224
Exploration Costs	157,400	16,605	5,911	13,970	193,886
Dry Hole Costs	43,215	12,408	(104)	(352)	55,167

Transportation Costs	260,628	9,819	247	3,396	274,090
Production Costs	682,230	136,084	41,973	7,697	867,984
Impairments	137,102	29,378	19,747	6,632	192,859
Depreciation, Depletion and Amortization	1,037,125	188,860	26,039	9,080	1,261,104
Income Before Income Taxes	2,750,276	335,555	299,294	11,009	3,396,134
Income Tax Provision	991,826	100,197	115,515	6,403	1,213,941
Results of Operations	$1,758,450	$235,358	$183,779	$ 4,606	$2,182,193

(1) Excludes gains or losses on the mark-to-market of financial commodity derivative contracts, gains or losses on sales of reserves and related assets, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2010.

(2) Other International primarily consists of EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth production costs per barrel of oil equivalent, excluding severance/production and ad valorem taxes, for the years ended December 31, 2010, 2009 and 2008:

	United States	Canada	Trinidad	Other International (1)	Composite
Year Ended December 31, 2010	$5.00	$10.28	$0.65	$ 9.34	$4.85
Year Ended December 31, 2009	$4.43	$8.41	$0.74	$ 10.52	$4.40
Year Ended December 31, 2008	$4.50	$8.05	$1.03	$ 7.33	$4.54

(1) Other International primarily consists of EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by ASC Topic 932 and based on crude oil, natural gas liquids and natural gas reserves and production volumes estimated by the Engineering and Acquisitions Department of EOG. The estimates were based on a 12-month average for commodity prices for the years 2010 and 2009 and year-end prices for the year 2008. The following information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating EOG or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of EOG.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil, natural gas liquids and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable and possible as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the standardized measure of discounted future net cash flows from projected production of EOG's oil and gas reserves for the years ended December 31, 2010, 2009 and 2008:

	United States	Canada	Trinidad	Other International (1)	Total
2010					
Future cash inflows (2)	$62,063,123	$6,040,422	$2,760,819	$ 91,805	$70,956,169
Future production costs	(22,616,039)	(2,711,415)	(384,147)	(48,953)	(25,760,554)
Future development costs	(9,596,005)	(1,716,734)	(198,072)	(334)	(11,511,145)
Future income taxes	(8,503,301)	(129,816)	(850,699)	(3,598)	(9,487,414)
Future net cash flows	21,347,778	1,482,457	1,327,901	38,920	24,197,056
Discount to present value at 10% annual rate	(10,718,854)	(736,222)	(339,035)	(11,121)	(11,805,232)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$10,628,924	$746,235	$988,866	$ 27,799	$12,391,824
2009					
Future cash inflows (3)	$34,506,336	$6,887,530	$2,133,778	$ 52,738	$43,580,382
Future production costs	(11,977,152)	(2,537,001)	(398,318)	(27,791)	(14,940,262)
Future development costs	(5,696,619)	(2,255,088)	(264,104)	(346)	(8,216,157)
Future income taxes	(5,307,041)	(249,986)	(525,873)	(4,276)	(6,087,176)
Future net cash flows	11,525,524	1,845,455	945,483	20,325	14,336,787
Discount to present value at 10% annual rate	(5,702,608)	(808,211)	(279,920)	(5,030)	(6,795,769)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$5,822,916	$1,037,244	$665,563	$ 15,295	$7,541,018
2008					
Future cash inflows (4)	$30,251,481	$6,522,526	$2,073,962	$ 82,842	$38,930,811
Future production costs	(10,378,028)	(2,100,701)	(475,725)	(35,504)	(12,989,958)
Future development costs	(3,270,509)	(395,609)	(259,155)	(6,174)	(3,931,447)
Future income taxes	(4,789,311)	(761,525)	(401,264)	(15,038)	(5,967,138)
Future net cash flows	11,813,633	3,264,691	937,818	26,126	16,042,268
Discount to present value at 10% annual rate	(5,505,921)	(1,513,539)	(336,765)	(6,142)	(7,362,367)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$6,307,712	$1,751,152	$601,053	$ 19,984	$8,679,901

(1) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

(2)

Estimated crude oil prices used to calculate 2010 future cash inflows for the United States, Canada, Trinidad and Other International were $76.38, $72.59, $69.56 and $73.88, respectively. Estimated natural gas liquids prices used to calculate 2010 future cash inflows for the United States and Canada were $43.85 and $26.56, respectively. Estimated natural gas prices used to calculate 2010 future cash inflows for the United States, Canada, Trinidad and Other International were $4.36, $3.67, $2.94 and $5.02, respectively.

(3) Estimated crude oil prices used to calculate 2009 future cash inflows for the United States, Canada, Trinidad and Other International were $53.64, $56.85, $51.35 and $52.87, respectively. Estimated natural gas liquids prices used to calculate 2009 future cash inflows for the United States and Canada were $28.75 and $19.31, respectively. Estimated natural gas prices used to calculate 2009 future cash inflows for the United States, Canada, Trinidad and Other International were $3.43, $3.50, $1.88 and $3.92, respectively.

(4) Estimated liquids prices used to calculate 2008 future cash inflows for the United States, Canada, Trinidad and Other International were $27.02, $25.44, $33.98 and $98.09, respectively. Estimated natural gas prices used to calculate 2008 future cash inflows for the United States, Canada, Trinidad and Other International were $5.05, $6.25, $1.49 and $5.14, respectively.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2010:

	United States	Canada	Trinidad	Other International	Total
December 31, 2007	$9,464,315	$2,434,683	$1,838,956	$43,668	$13,781,622
Sales and transfers of oil and gas produced, net of production costs	(4,106,925)	(581,804)	(350,842)	(40,338)	(5,079,909)
Net changes in prices and production costs	(5,043,379)	(709,659)	(2,148,861)	(9,820)	(7,911,719)
Extensions, discoveries, additions and improved recovery, net of related costs	2,187,722	107,545	-	-	2,295,267
Development costs incurred	736,800	19,400	30,600	-	786,800
Revisions of estimated development cost	(5,329)	41,666	69,261	1,621	107,219
Revisions of previous quantity estimates	(184,671)	48,638	47,606	(22,611)	(111,038)
Accretion of discount	1,312,902	281,860	299,304	8,734	1,902,800
Net change in income taxes	1,676,106	141,767	909,920	31,340	2,759,133
Purchases of reserves in place	120,300	26,002	4,886	14,559	165,747
Sales of reserves in place	(277,781)	-	-	-	(277,781)
Changes in timing and other	427,652	(58,946)	(99,777)	(7,169)	261,760
December 31, 2008	6,307,712	1,751,152	601,053	19,984	8,679,901
Sales and transfers of oil and gas produced, net of production costs	(1,904,912)	(259,301)	(200,892)	(12,443)	(2,377,548)
Net changes in prices and production costs	(1,482,778)	(902,629)	338,053	(13,868)	(2,061,222)
Extensions, discoveries, additions and improved recovery, net of related costs	1,702,471	259,305	-	-	1,961,776
Development costs incurred	344,500	14,200	-	-	358,700
Revisions of estimated development cost	595,875	68,883	(3,380)	4,555	665,933
Revisions of previous quantity estimates	(422,294)	(425,018)	(124,222)	1,016	(970,518)
Accretion of discount	829,631	199,330	84,521	3,232	1,116,714
Net change in income taxes	261,513	259,169	(105,766)	9,847	424,763
Purchases of reserves in place	209,130	-	-	-	209,130
Sales of reserves in place	(264,482)	(13,912)	-	-	(278,394)
Changes in timing and other	(353,450)	86,065	76,196	2,972	(188,217)
December 31, 2009	5,822,916	1,037,244	665,563	15,295	7,541,018
Sales and transfers of oil and gas produced, net of production costs	(2,792,005)	(292,857)	(395,379)	(17,720)	(3,497,961)
Net changes in prices and production costs	2,468,907	(559)	721,796	7,259	3,197,403
Extensions, discoveries, additions and improved recovery, net of related costs	4,319,659	75,162	183,453	-	4,578,274
Development costs incurred	864,700	175,100	67,300	-	1,107,100
Revisions of estimated development cost	(257,360)	260,290	(767)	9	2,172
Revisions of previous quantity estimates	(164,748)	(38,382)	(175,002)	4,006	(374,126)
Accretion of discount	755,001	102,022	101,549	1,778	960,350

Net change in income taxes	(1,171,384)	101,966	(258,354)	2,469	(1,325,303)
Purchases of reserves in place	265	-	-	-	265
Sales of reserves in place	(54,057)	(290,592)	-	-	(344,649)
Changes in timing and other	837,030	(383,159)	78,707	14,703	547,281
December 31, 2010	$10,628,924	$746,235	$988,866	$ 27,799	$12,391,824

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EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

Unaudited Quarterly Financial Information
(In Thousands, Except Per Share Data)

Quarter Ended	Mar 31	Jun 30	Sep 30	Dec 31
2010				
Net Operating Revenues	$1,370,693	$1,357,968	$1,582,075	$1,789,160
Operating Income (Loss)	$219,902	$140,501	$(11,695)	$174,611
Income (Loss) Before Income Taxes	$197,157	$110,059	$(38,813)	$139,573
Income Tax Provision	79,142	50,187	32,093	85,900
Net Income (Loss)	$118,015	$59,872	$(70,906)	$53,673
Net Income (Loss) Per Share (1)				
Basic	$0.47	$0.24	$(0.28)	$0.21
Diluted	$0.46	$0.24	$(0.28)	$0.21
Average Number of Common Shares				
Basic	250,370	250,825	251,015	251,365
Diluted	253,869	254,503	251,015	254,721
2009				
Net Operating Revenues	$1,158,209	$861,039	$1,006,849	$1,760,862
Operating Income	$281,412	$18	$35,303	$654,108
Income (Loss) Before Income Taxes	$264,775	$(23,556)	$4,557	$626,235
Income Tax Provision (Benefit)	106,065	(6,850)	361	225,808
Net Income (Loss)	$158,710	$(16,706)	$4,196	$400,427
Net Income (Loss) Per Share (1)				
Basic	$0.64	$(0.07)	$0.02	$1.60
Diluted	$0.63	$(0.07)	$0.02	$1.58
Average Number of Common Shares				
Basic	247,991	248,207	249,535	250,127
Diluted	250,204	248,207	252,422	253,493

(1) The sum of quarterly net income (loss) per share may not agree with total year net income (loss) per share as each quarterly computation is based on the weighted average of common shares outstanding.

Schedule II

EOG RESOURCES, INC.

VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2010, 2009 and 2008

(In Thousands)

Column A	Column B	Column C	Column D	Column E
Description	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Deductions From Reserves	Balance at End of Year
2010				
Allowance deducted from Accounts Receivable	$13,228	$885	$471	$13,642
2009				
Allowance deducted from Accounts Receivable	$13,131	$145	$48	$13,228
2008				
Allowance deducted from Accounts Receivable	$16,019	$57	$2,945	$13,131

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EXHIBITS

Exhibits not incorporated herein by reference to a prior filing are designated by (i) an asterisk (*) and are filed herewith; or (ii) a pound sign (#) and are not filed herewith, and, pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, the registrant hereby agrees to furnish a copy of such exhibit to the United States Securities and Exchange Commission (SEC) upon request.

Exhibit Number		Description
3.1(a)	-	Restated Certificate of Incorporation, dated September 3, 1987 (Exhibit 3.1(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
3.1(b)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 5, 1993 (Exhibit 4.1(b) to EOG's Registration Statement on Form S-8, SEC File No. 33-52201, filed February 8, 1994).
3.1(c)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 14, 1994 (Exhibit 4.1(c) to EOG's Registration Statement on Form S-8, SEC File No. 33-58103, filed March 15, 1995).
3.1(d)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 11, 1996 (Exhibit 3(d) to EOG's Registration Statement on Form S-3, SEC File No. 333-09919, filed August 9, 1996).
3.1(e)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 7, 1997 (Exhibit 3(e) to EOG's Registration Statement on Form S-3, SEC File No. 333-44785, filed January 23, 1998).
3.1(f)	-	Certificate of Ownership and Merger Merging EOG Resources, Inc. into Enron Oil & Gas Company, dated August 26, 1999 (Exhibit 3.1(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
3.1(g)	-	Certificate of Designations of Series E Junior Participating Preferred Stock, dated February 14, 2000 (Exhibit 2 to EOG's Registration Statement on Form 8-A, SEC File No. 001-09743, filed February 18, 2000).
3.1(h)	-	Certificate of Elimination of the Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, dated September 13, 2000 (Exhibit 3.1(j) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(i)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series C, dated September 13, 2000 (Exhibit 3.1(k) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(j)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series D, dated February 24, 2005 (Exhibit 3.1(k) to EOG's Annual Report on Form 10-K for the year ended December 31, 2004) (SEC File No. 001-09743).

3.1(k)	-	Amended Certificate of Designations of Series E Junior Participating Preferred Stock, dated March 7, 2005. (Exhibit 3.1(m) to EOG's Annual Report on Form 10-K for the year ended December 31, 2007).
3.1(l)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 3, 2005 (Exhibit 3.1(l) to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005) (SEC File No. 001-09743).
3.1(m)	-	Certificate of Elimination of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, dated March 6, 2008 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed March 6, 2008).
3.2	-	Bylaws, as amended and restated effective as of February 26, 2009 (Exhibit 3.2(a) to EOG's Current Report on Form 8-K, filed March 4, 2009).

Exhibit Number		Description
4.1	-	Specimen of Certificate evidencing EOG's Common Stock (Exhibit 3.3 to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
4.2	-	Indenture, dated as of September 1, 1991, between Enron Oil & Gas Company (predecessor to EOG) and The Bank of New York Mellon Trust Company, N.A. (as successor in interest to JPMorgan Chase Bank, N.A. (formerly, Texas Commerce Bank National Association)), as Trustee (Exhibit 4(a) to EOG's Registration Statement on Form S-3, SEC File No. 33-42640, filed September 6, 1991).
4.3(a)	-	Officers' Certificate Establishing 6.125% Senior Notes due 2013 and 6.875% Senior Notes due 2018, dated September 30, 2008 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 30, 2008).
4.3(b)	-	Form of Global Note with respect to the 6.125% Senior Notes due 2013 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 30, 2008).
4.3(c)	-	Form of Global Note with respect to the 6.875% Senior Notes due 2018 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed September 30, 2008).
4.4(a)	-	Officers' Certificate Establishing 5.875% Senior Notes due 2017 of EOG, dated September 10, 2007 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 10, 2007).
4.4(b)	-	Form of Global Note with respect to the 5.875% Senior Notes due 2017 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 10, 2007).
#4.5(a)	-	Certificate, dated April 3, 1998, of the Senior Vice President and Chief Financial Officer of Enron Oil & Gas Company (predecessor to EOG) establishing the terms of the 6.65% Notes due April 1, 2028.
#4.5(b)	-	Global Note with respect to the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company (predecessor to EOG).
#4.6(a)	-	Indenture, dated as of November 15, 2001, between EOG Company of Canada, as Issuer, and Wells Fargo Bank, National Association, as successor Trustee, with respect to the 7.00% Senior Notes due 2011 of EOG Company of Canada.
#4.6(b)	-	First Supplemental Indenture, dated as of April 2, 2002, to the Indenture, dated as of November 15, 2001, between EOG Company of Canada, as Issuer, and Wells Fargo Bank, National Association, as successor Trustee, with respect to the 7.00% Senior Notes due 2011 of EOG Company of Canada.
#4.7	-	Indenture, dated as of March 1, 2004, between EOG Resources Canada Inc., as Issuer, and The Bank of New York Trust Company, N.A., as Trustee, with respect

		to the 4.75% Senior Notes due 2014 of EOG Resources Canada Inc.
4.8	-	Indenture, dated as of May 18, 2009, between EOG and Wells Fargo Bank, NA, as Trustee (Exhibit 4.9 to EOG's Registration Statement on Form S-3, SEC File No. 333-159301, filed May 18, 2009).
4.9(a)	-	Officers' Certificate Establishing 5.625% Senior Notes due 2019 of EOG, dated May 21, 2009 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 21, 2009).
4.9(b)	-	Form of Global Note with respect to the 5.625% Senior Notes due 2019 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed May 21, 2009).

Exhibit Number		Description
4.10(a)	-	Officers' Certificate Establishing 2.95% Senior Notes due 2015 and 4.40% Senior Notes due 2020, dated May 20, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 26, 2010).
4.10(b)	-	Form of Global Note with respect to the 2.95% Senior Notes due 2015 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed May 26, 2010).
4.10(c)	-	Form of Global Note with respect to the 4.40% Senior Notes due 2020 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed May 26, 2010).
4.11(a)	-	Officers' Certificate Establishing 2.500% Senior Notes due 2016, 4.100% Senior Notes due 2021 and Floating Rate Senior Notes due 2014, dated November 23, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed November 24, 2010).
4.11(b)	-	Form of Global Note with respect to the 2.500% Senior Notes due 2016 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed November 24, 2010).
4.11(c)	-	Form of Global Note with respect to the 4.100% Senior Notes due 2021 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed November 24, 2010).
4.11(d)	-	Form of Global Note with respect to the Floating Rate Senior Notes due 2014 of EOG (Exhibit 4.5 to EOG's Current Report on Form 8-K, filed November 24, 2010).
10.1(a)+	-	EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 8, 2008 (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(b)+	-	First Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of September 4, 2008 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008).
10.1(c)+	-	Second Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of January 1, 2010 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.1(d)+	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(e)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed May 14, 2008).

10.1(f)	-	Form of Nonemployee Director Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(g)+	-	Form of Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.5 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(h)+	-	Form of Restricted Stock Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.6 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(i)	-	Form of Nonemployee Director Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.7 to EOG's Current Report on Form 8-K, filed May 14, 2008).

Exhibit Number		Description
10.2(a)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Plan Document, effective as of December 16, 2008 (Exhibit 10.2(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
10.2(b)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Adoption Agreement, dated as of December 16, 2008 (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
10.3(a)+	-	Amended and Restated Enron Oil & Gas Company 1994 Stock Plan (Exhibit 4.3 to EOG's Registration Statement on Form S-8, SEC File No. 33-58103, filed March 15, 1995).
10.3(b)+	-	Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 12, 1995 (Exhibit 4.3(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 1995) (SEC File No. 001-09743).
10.3(c)+	-	Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 10, 1996 (Exhibit 4.3(a) to EOG's Registration Statement on Form S-8, SEC File No. 333-20841, filed January 31, 1997).
10.3(d)+	-	Third Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 9, 1997 (Exhibit 4.3(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 1997) (SEC File No. 001-09743).
10.3(e)+	-	Fourth Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of May 5, 1998 (Exhibit 4.3(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998) (SEC File No. 001-09743).
10.3(f)+	-	Fifth Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 8, 1998 (Exhibit 4.3(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998) (SEC File No. 001-09743).
10.3(g)+	-	Sixth Amendment to Amended and Restated EOG Resources, Inc. 1994 Stock Plan, dated effective as of May 8, 2001 (Exhibit 10.1(g) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001) (SEC File No. 001-09743).
10.3(h)+	-	Seventh Amendment to Amended and Restated EOG Resources, Inc. 1994 Stock Plan, dated effective as of December 30, 2005 (Exhibit 10.1(h) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005) (SEC File No. 001-09743).

10.4(a)	-	EOG Resources, Inc. 1993 Nonemployee Directors Stock Option Plan, as amended and restated effective May 7, 2002 (Exhibit A to EOG's Proxy Statement, filed March 28, 2002, with respect to EOG's 2002 Annual Meeting of Stockholders) (SEC File No. 001-09743).
10.4(b)	-	First Amendment to EOG Resources, Inc. 1993 Nonemployee Directors Stock Option Plan, dated effective as of December 30, 2005 (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005) (SEC File No. 001-09743).
10.5(a)+	-	EOG Resources, Inc. 1992 Stock Plan, as amended and restated effective May 4, 2004 (Exhibit B to EOG's Proxy Statement, filed March 29, 2004, with respect to EOG's 2004 Annual Meeting of Stockholders) (SEC File No. 001-09743).
10.5(b)+	-	First Amendment to EOG Resources, Inc. 1992 Stock Plan, dated effective as of December 30, 2005 (Exhibit 10.3(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005) (SEC File No. 001-09743).

Exhibit Number		Description
10.6(a)+	-	Executive Employment Agreement between EOG and Mark G. Papa, effective as of June 15, 2005 (Exhibit 99.1 to EOG's Current Report on Form 8-K filed, June 21, 2005) (SEC File No. 001-09743).
10.6(b)+	-	First Amendment to Executive Employment Agreement between EOG and Mark G. Papa, effective as of March 16, 2009 (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed March 18, 2009).
10.6(c)+	-	Amended and Restated Change of Control Agreement between EOG and Mark G. Papa, effective as of June 15, 2005 (Exhibit 99.6 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.6(d)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Mark G. Papa, effective as of April 30, 2009 (Exhibit 10.1(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.7(a)+	-	Executive Employment Agreement between EOG and Loren M. Leiker, effective as of June 15, 2005 (Exhibit 99.3 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.7(b)+	-	First Amendment to Executive Employment Agreement between EOG and Loren M. Leiker, effective as of March 16, 2009 (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed March 18, 2009).
10.7(c)+	-	Amended and Restated Change of Control Agreement between EOG and Loren M. Leiker, effective as of June 15, 2005 (Exhibit 99.8 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.7(d)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Loren M. Leiker, effective as of April 30, 2009 (Exhibit 10.2(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.8(a)+	-	Executive Employment Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.4 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.8(b)+	-	First Amendment to Executive Employment Agreement between EOG and Gary L. Thomas, effective as of March 16, 2009 (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed March 18, 2009).
10.8(c)+	-	Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.9 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.8(d)+	-	

		First Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of April 30, 2009 (Exhibit 10.3(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.9(a)+	-	Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of June 15, 2005 (Exhibit 99.11 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.9(b)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of April 30, 2009 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).

Exhibit Number		Description
10.10(a)+	-	Executive Employment Agreement between EOG and Frederick J. Plaeger, II, effective as of April 23, 2007 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.10(b)+	-	First Amendment to Executive Employment Agreement between EOG and Frederick J. Plaeger, II, effective as of April 30, 2009 (Exhibit 10.4(a) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.10(c)+	-	Change of Control Agreement between EOG and Frederick J. Plaeger, II, effective as of April 23, 2007 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.10(d)+	-	First Amendment to Change of Control Agreement between EOG and Frederick J. Plaeger, II, effective as of April 30, 2009 (Exhibit 10.4(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.11(a)+	-	EOG Resources, Inc. Change of Control Severance Plan, as amended and restated effective as of June 15, 2005 (Exhibit 99.12 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.11(b)+	-	First Amendment to the EOG Resources, Inc. Change of Control Severance Plan, effective as of April 30, 2009 (Exhibit 10.6 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.12+	-	EOG Resources, Inc. Amended and Restated Executive Officer Annual Bonus Plan (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.13(a)+	-	EOG Resources, Inc. Employee Stock Purchase Plan (Exhibit 4.4 to EOG’s Registration Statement on Form S-8, SEC File No. 333-62256, filed June 4, 2001).
10.13(b)+	-	Amendment to EOG Resources, Inc. Employee Stock Purchase Plan, dated effective as of January 1, 2010 (Exhibit 4.3(b) to EOG’s Registration Statement on Form S-8, SEC File No. 333-166518, filed May 4, 2010).
10.14(a)	-	Revolving Credit Agreement, dated as of June 28, 2005, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005) (SEC File No. 001-09743).
10.14(b)	-	First Amendment to Revolving Credit Agreement, dated as of June 21, 2006, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.14(c)	-	

		Second Amendment to Revolving Credit Agreement, dated as of May 18, 2007, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10.14(d)	-	Third Amendment to Revolving Credit Agreement, dated as of September 14, 2007, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.15	-	Revolving Credit Agreement, dated as of September 10, 2010, among EOG, Bank of America, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed September 14, 2010).

Exhibit Number		Description
* 12	-	Computation of Ratio of Earnings to Fixed Charges and to Combined Fixed Charges and Preferred Stock Dividends.
* 21	-	Subsidiaries of EOG, as of December 31, 2010.
* 23.1	-	Consent of DeGolyer and MacNaughton.
* 23.2	-	Opinion of DeGolyer and MacNaughton dated January 31, 2011.
* 23.3	-	Consent of Deloitte & Touche LLP.
* 24	-	Powers of Attorney.
* 31.1	-	Section 302 Certification of Annual Report of Principal Executive Officer.
* 31.2	-	Section 302 Certification of Annual Report of Principal Financial Officer.
* 32.1	-	Section 906 Certification of Annual Report of Principal Executive Officer.
* 32.2	-	Section 906 Certification of Annual Report of Principal Financial Officer.
* **101.INS	-	XBRL Instance Document.
* **101.SCH	-	XBRL Schema Document.
* **101.CAL	-	XBRL Calculation Linkbase Document.
* **101.LAB	-	XBRL Label Linkbase Document.
* **101.PRE	-	XBRL Presentation Linkbase Document.
* **101.DEF	-	XBRL Definition Linkbase Document.

*Exhibits filed herewith

**Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income and Comprehensive Income for Each of the Three Years in the Period Ended December 31, 2010, (ii) the Consolidated Balance Sheets - December 31, 2010 and 2009, (iii) the Consolidated Statements of Stockholders' Equity for Each of the Three Years in the Period Ended December 31, 2010, (iv) the Consolidated Statements of Cash Flows for Each of the Three Years in the Period Ended December 31, 2010 and (v) Notes to Consolidated Financial Statements. Users of this data are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

+ Management contract, compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EOG RESOURCES, INC.
(Registrant)

Date: February 24, 2011	By:	/s/ TIMOTHY K. DRIGGERS Timothy K. Driggers Vice President and Chief Financial Officer (Principal Financial Officer and Duly Authorized Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities with EOG Resources, Inc. indicated and on the 24th day of February, 2011.

Signature	Title
/s/ MARK G. PAPA (Mark G. Papa)	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)
/s/ TIMOTHY K. DRIGGERS (Timothy K. Driggers)	Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ ANN D. JANSSEN (Ann D. Janssen)	Vice President, Accounting (Principal Accounting Officer)
* (George A. Alcorn)	Director
* (Charles R. Crisp)	Director
* (James C. Day)	Director
* (H. Leighton Steward)	Director
* (Donald F. Textor)	Director
* (Frank G. Wisner)	Director

*By /s/ MICHAEL P. DONALDSON
(Michael P. Donaldson)
(Attorney-in-fact for persons indicated)

EOG RESOURCES, INC. AND SUBSIDIARIES
EXHIBITS TO FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010
INDEX OF EXHIBITS

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