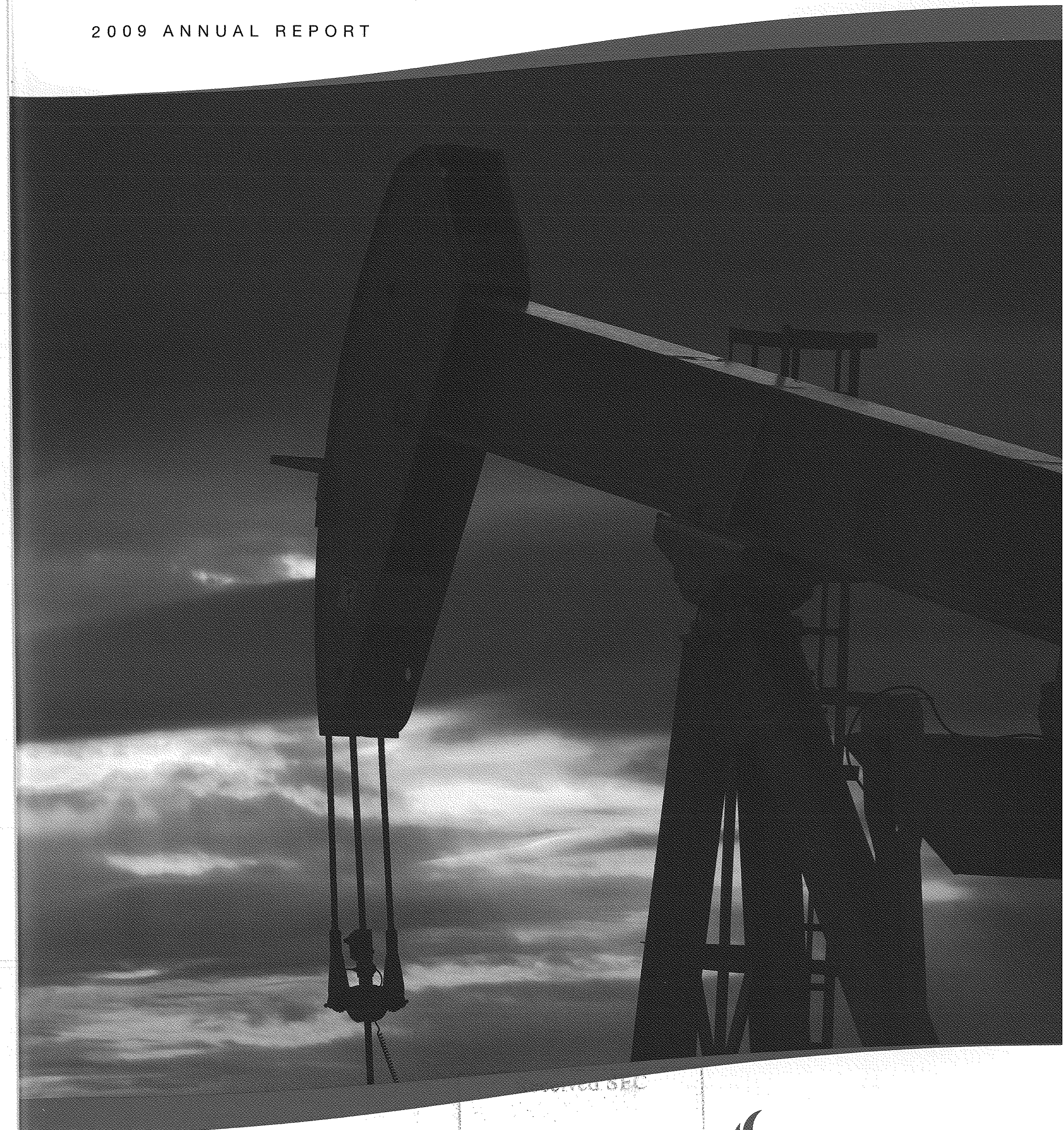
Developing New Frontiers in Horizontal Oil

2009 ANNUAL REPORT



eog resources

FINANCIAL AND OPERATING HIGHLIGHTS

(In millions, except per share data, unless otherwise indicated)	**2009**	2008	2007
Net Operating Revenues	**$ 4,787**	$ 7,127	$ 4,239
Income Before Interest Expense and Income Taxes	**$ 973**	$ 3,798	$ 1,678
Net Income Available to Common Stockholders	**$ 547**	$ 2,436	$ 1,083
Total Exploration and Development Expenditures	**$ 3,908**	$ 5,093	$ 3,599
Other Property, Plant and Equipment Expenditures	**$ 326**	$ 477	$ 277
Wellhead Statistics			
Natural Gas Volumes (MMcfd)	**1,645**	1,619	1,470
Average Natural Gas Prices ($/Mcf)	**$ 3.42**	$ 7.51	$ 5.65
Crude Oil and Condensate Volumes (MBbld)	**55.2**	45.5	31.2
Average Crude Oil and Condensate Prices ($/Bbl)	**$ 54.46**	$ 88.18	$ 68.69
Natural Gas Liquids Volumes (MBbld)	**23.6**	16.0	12.2
Average Natural Gas Liquids Prices ($/Bbl)	**$ 30.05**	$ 53.42	$ 47.36
NYSE Price Range ($/Share)			
High	**$ 101.76**	$ 144.99	$ 91.63
Low	**$ 45.03**	$ 54.42	$ 59.21
Close	**$ 97.30**	$ 66.58	$ 89.25
Cash Dividends Per Common Share Declared	**$ 0.58**	$ 0.51	$ 0.36
Diluted Average Number of Common Shares Outstanding	**251.9**	250.5	247.6

THE COMPANY

EOG Resources, Inc. (EOG) is one of the largest independent (non-integrated) oil and natural gas companies in the United States with proved reserves in the United States, Canada, Trinidad, the United Kingdom and China. EOG is listed on the New York Stock Exchange and is traded under the ticker symbol "EOG."

ON THE COVER

A crude oil pumping unit symbolizes the shift toward a more balanced mix of crude oil and natural gas in EOG's North American production portfolio.

HIGHLIGHTS

- In 2009, EOG reported net income available to common stockholders of $546.6 million as compared to $2,436.5 million for 2008.
- EOG delivered 6.5 percent year-over-year total company organic production growth.
- Total North American liquids production increased 30 percent, comprised of 23 percent growth in crude oil and condensate and 48 percent in natural gas liquids, driven by ongoing exploration and development drilling in the North Dakota Bakken and Fort Worth Barnett Shale Combo Plays.
- Total company proved reserves were approximately 10.8 Tcfe, an increase of 2,087 Bcfe, or 24 percent higher than year-end 2008.
- EOG maintained a conservative balance sheet, ending the year with a net debt-to-total capitalization ratio(1) of 17 percent.
- Following an increase in the common stock dividend in 2009, EOG's Board of Directors again increased the cash dividend on the common stock. Effective with the dividend payable on April 30, 2010 to holders of record as of April 16, 2010, the quarterly dividend on the common stock will be $0.155 per share, an increase of 7 percent over the previous indicated annual rate. The current indicated annual rate of $0.62 per share reflects the 11th increase in 11 years.
- EOG was named to *Fortune's* list of "100 Best Companies to Work For®" for the fourth consecutive year it has been eligible for consideration.

(1) Refer to reconciliation schedule on page 105.

For information regarding forward-looking statements, see pages 43-44 of EOG's Form 10-K included herein.

For a glossary of terms, see page 106.

Developing New Frontiers in Horizontal Oil

Our strategy shift toward a more balanced portfolio with an increased focus on crude oil and natural gas liquids is well underway.

While our long-standing fundamentals remain intact, EOG can no longer be considered primarily a natural gas company. Our strategy shift toward a more balanced portfolio with an increased focus on crude oil and natural gas liquids is well underway.

We are accomplishing this significant transformation by successfully adapting the same technological skill set that we honed in horizontal natural gas shale plays to unlock challenging new liquids-rich unconventional reservoirs. Our proficiency in identifying viable geologic play candidates and the application of industry leading completion techniques is providing EOG with a competitive advantage in a number of different North American petroleum basins. EOG is at the forefront of the industry in developing new frontiers in horizontal oil.

The decision to move a greater portion of EOG's capital expenditures and exploration budget away from natural gas toward crude oil and natural gas liquids began several years ago. It was based not only on EOG's demonstrated technical edge but also our long-term view of North American natural gas and global crude oil market fundamentals. Since we made this strategic decision, we have captured commanding positions in several proved and prospective oil plays that will drive our liquids production growth for many years to come.

Loren M. Leiker Senior Executive Vice President, Exploration | **Mark G. Papa** Chairman and Chief Executive Officer | **Gary L. Thomas** Senior Executive Vice President, Operations

OUTLOOK FOR NORTH AMERICAN MARKETS

EOG expects North American natural gas prices to be fairly static during the first half of 2010 but rebound in the second half of the year as the decline in North America's natural gas supply becomes more apparent. However, due to the industry's overwhelming horizontal drilling success in natural gas shale plays, our long-term view of North American natural gas continues to be that future price growth will be less robust than that of crude oil. By decreasing our exposure to natural gas, EOG will be less dependent on vagaries such as weather, as well as the impact from liquefied natural gas and Canadian imports. Factors such as these have caused extreme volatility in natural gas prices and wide revenue swings.

In contrast, NYMEX crude oil prices have been surprisingly robust with the second half of 2009 averaging over $72 per barrel. We anticipate that prices will average over $75 per barrel during 2010 and likely increase further over the next 10 years and beyond. Global demographic trends, particularly in Asia, suggest that total worldwide demand for crude oil is expected to significantly increase over the next 20 years as population growth and per capita utilization increase in the developing world.

The fiscal discipline that is one of EOG's key attributes provides us with the balance sheet flexibility to pursue exploration concepts in a variety of market conditions. This provides EOG with the ability to maintain a steady exploration program and expand acreage positions at favorable early-mover costs

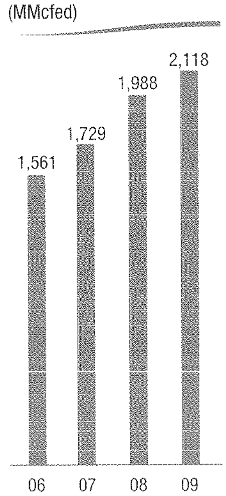
EOG's transformation into a more balanced crude oil and natural gas company will be accomplished without significantly changing the precepts on which our company has been built.

CHANGING STRATEGY BUT NOT FOCUS

For the past decade, EOG has been a heavily weighted North American natural gas producer. In 1999, 81 percent of our total wellhead revenues and 86 percent of our North American volumes were natural gas. In 2009, 60 percent of our total wellhead revenues and 75 percent of our North American volumes were derived from natural gas.

In 2010, we expect EOG's North American revenue mix to be divided almost equally between liquids and natural gas. However, EOG is not walking away from natural gas. Over the years, we have organically developed and captured early-mover acreage positions in such outstanding shale plays as the Fort Worth Barnett, British Columbia Horn River Basin, Haynesville and Marcellus. While these plays will drive EOG's North American natural gas production growth in 2010, we will continue to access our deep inventory of high rate-of-return natural gas assets when markets are favorable.

EOG DAILY PRODUCTION
(MMcfed)



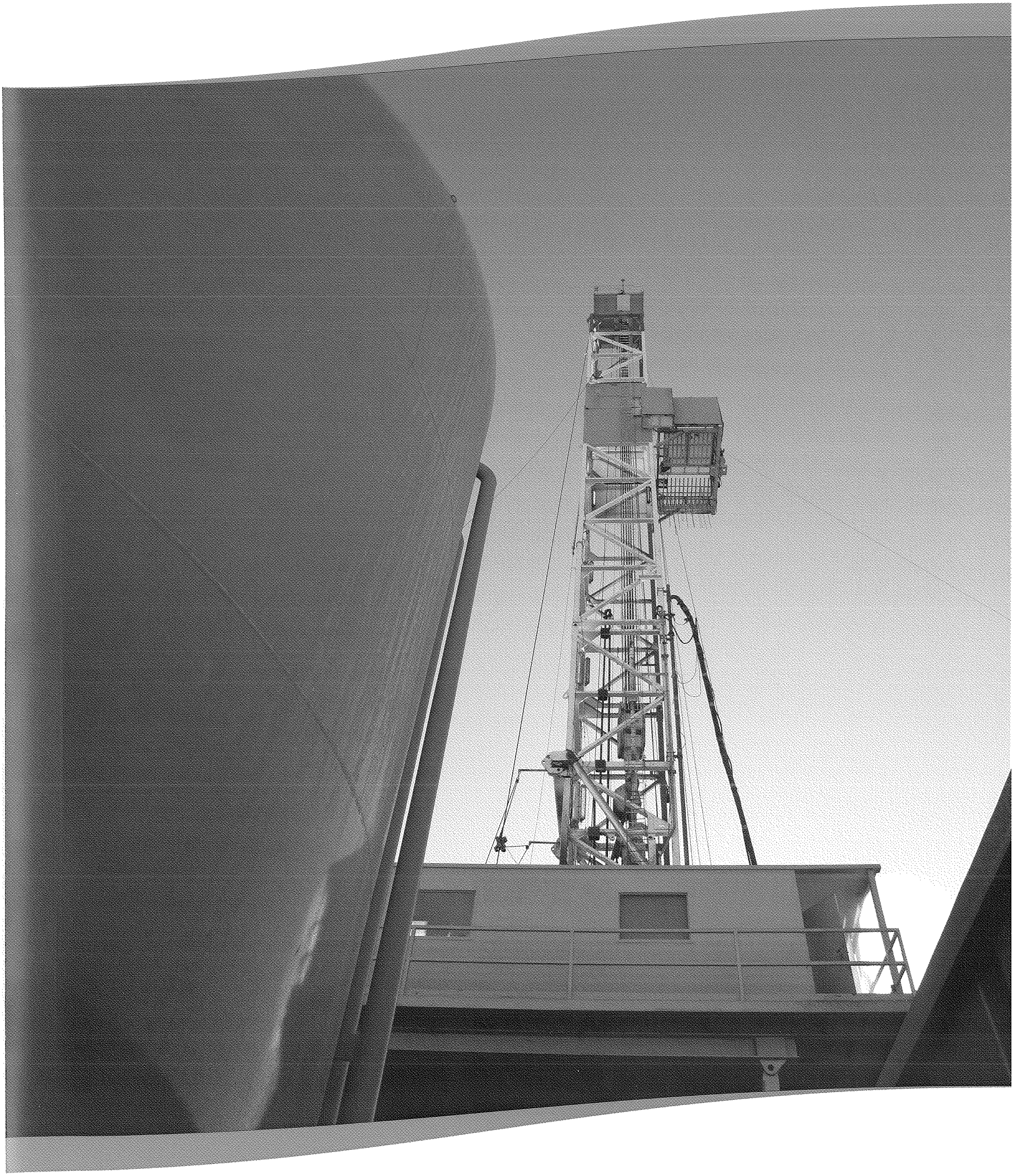
when there is little competition. At year-end 2009, EOG had a net debt-to-total capitalization ratio[2] of 17 percent.

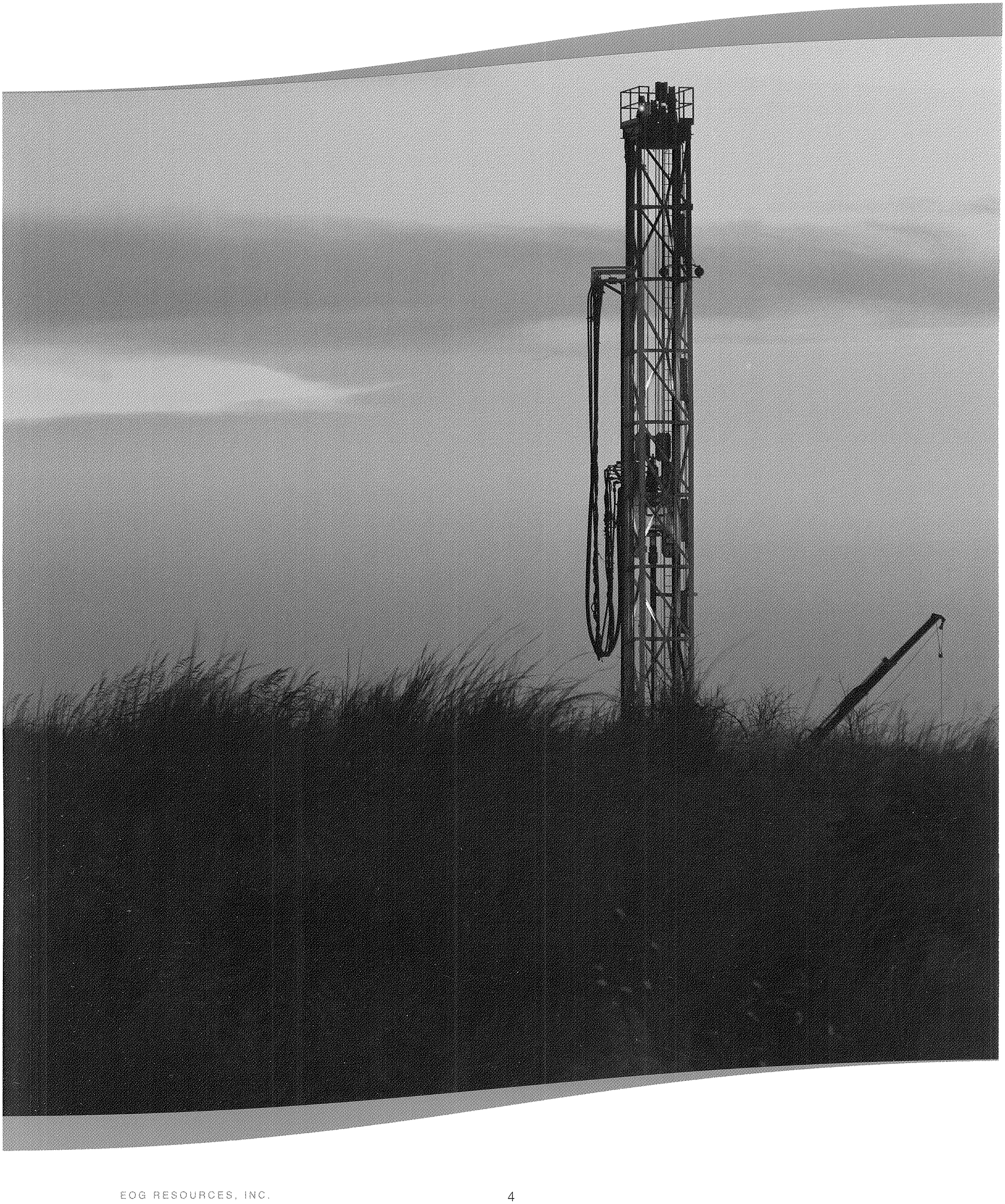
EOG's transformation into a more balanced crude oil and natural gas company will be accomplished without significantly changing the precepts on which our company has been built. We will maintain EOG's long-standing high rate of return organic approach – by growing through the drillbit – rather than seeking major mergers and/or acquisitions.

We will continue to pursue EOG's consistent game plan because it yields consistent results for our stockholders by generating strong debt-adjusted production growth per share. We will still add value by remaining a low cost producer, monitoring the balance sheet, maintaining a low debt level and focusing on return on capital employed (ROCE).

FUELING EOG'S MOMENTUM

The two biggest contributors to EOG's 2010 crude oil and natural gas liquids





growth will be the Fort Worth Barnett Shale Combo and North Dakota Bakken Plays.

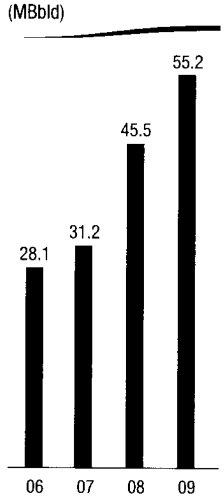
EOG holds a major position in the Fort Worth Barnett Shale Combo, a crude oil and liquids-rich natural gas trend in the Fort Worth Basin, outside the core natural gas area. In 2010, we will move into development drilling of both vertical and horizontal wells in eastern Montague and western Cooke Counties.

With a position of over 500,000 net acres in the North Dakota Bakken, we have expanded our development activities beyond Bakken wells in the Core Parshall Field by drilling wells in the Bakken Lite and Three Forks Formation. Initial production profiles from the Three Forks are encouraging with recoverable reserves expected to be similar to the Bakken Lite.

Last year when EOG recognized that crude oil production in the North Dakota Bakken exceeded the pipeline capacity in the basin, we built and placed in operation a rail transportation system. Designed to initially facilitate one unit train per day with a maximum capacity of 60,000 gross barrels, the system is comprised of a crude oil loading facility in Stanley, North Dakota, an unloading facility in Stroud, Oklahoma and a 17-mile pipeline running from that point to a terminal in Cushing, Oklahoma. The project is an example of EOG's agility, its ability to make decisions quickly and to implement solutions to resolve issues that might stymie other operators.

While the Fort Worth Barnett Shale Combo and North Dakota Bakken Plays are expected to provide significant momentum for the foreseeable future, EOG is pursuing additional horizontal crude oil and liquids-rich concepts in basins across North America.

EOG DAILY CRUDE OIL AND CONDENSATE PRODUCTION
(MBbld)



RETURNS STILL MATTER

EOG's goal always has been to be the best rather than the biggest exploration and production company. We continue to define "best" as measured by delivering superior stockholder value.

For the three, five and 10-year periods ended December 31, 2009, EOG's stock appreciation was 56 percent, 173 percent and 1,008 percent, respectively, significantly exceeding the performance of the S&P 500 Oil and Gas Exploration and Production Index for these three periods.

EOG's persistence in managing costs and maximizing reserve recoveries has resulted in superior returns, year after year. Our average ROCE[2] for the 10-year period ended December 31, 2009 was 18 percent. EOG's outperformance on stockholder returns and ROCE validates its long-term organic growth strategy.

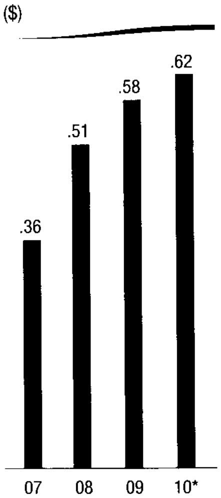
EOG's persistence in managing costs and maximizing reserve recoveries has resulted in superior returns, year after year.

EOG reported net income available to common stockholders of $547 million in 2009, or $2.17 per share as compared to $2,436 million, or $9.72 per share in 2008. For the year, total company production increased 6.5 percent, with a 28 percent increase in total company crude oil and natural gas liquids production.

At December 31, 2009, EOG's total proved reserves were approximately 10.8 Tcfe, an increase of 2.1 Tcfe, or 24 percent higher than year-end 2008. Total reserve replacement from all sources[2] was 364 percent at attractive total reserve replacement costs.

Following an increase in 2009, the EOG Board of Directors again increased the cash dividend on the common stock in February 2010. Effective with the dividend payable on April 30, 2010 to holders of record as of April 16, 2010, the quarterly dividend on the common stock will be $0.155 per share, an increase of 7 percent over the previous indicated annual rate. The current indicated annual rate of $0.62 per share reflects the 11th increase in 11 years.

EOG CASH DIVIDENDS PER COMMON SHARE DECLARED
($)



** Indicated current level*

EOG'S PEOPLE MAKE THE DIFFERENCE

EOG delivers strong, steady results year-in and year-out because of the tenacity, creativity and commitment of approximately 2,100 employees, whom we consider unparalleled in any industry. They work hard, they work safely and they are committed to increasing stockholder value and safeguarding the environment. They also make a positive difference in their communities by contributing their talent, time and resources. Although EOG recently was named again to *Fortune's* list of "100 Best Companies to Work For®" for the fourth consecutive year that it has been eligible,

EOG delivers strong, steady results year-in and year-out because of the tenacity, creativity and commitment of approximately 2,100 employees, whom we consider unparalleled in any industry.

the laurels rightfully go to our employees. They have made EOG what it is, and we salute their efforts.

We all are proud of what EOG has accomplished as primarily a natural gas company over the past decade. Looking ahead, we have an early-mover position in several horizontal crude oil concepts, plus we are optimistic about the strength of crude oil prices in the future. Therefore, our long-term ROCE outperformance versus our peers can be perpetuated over the next decade, which should continue to be reflected in superior stockholder returns.

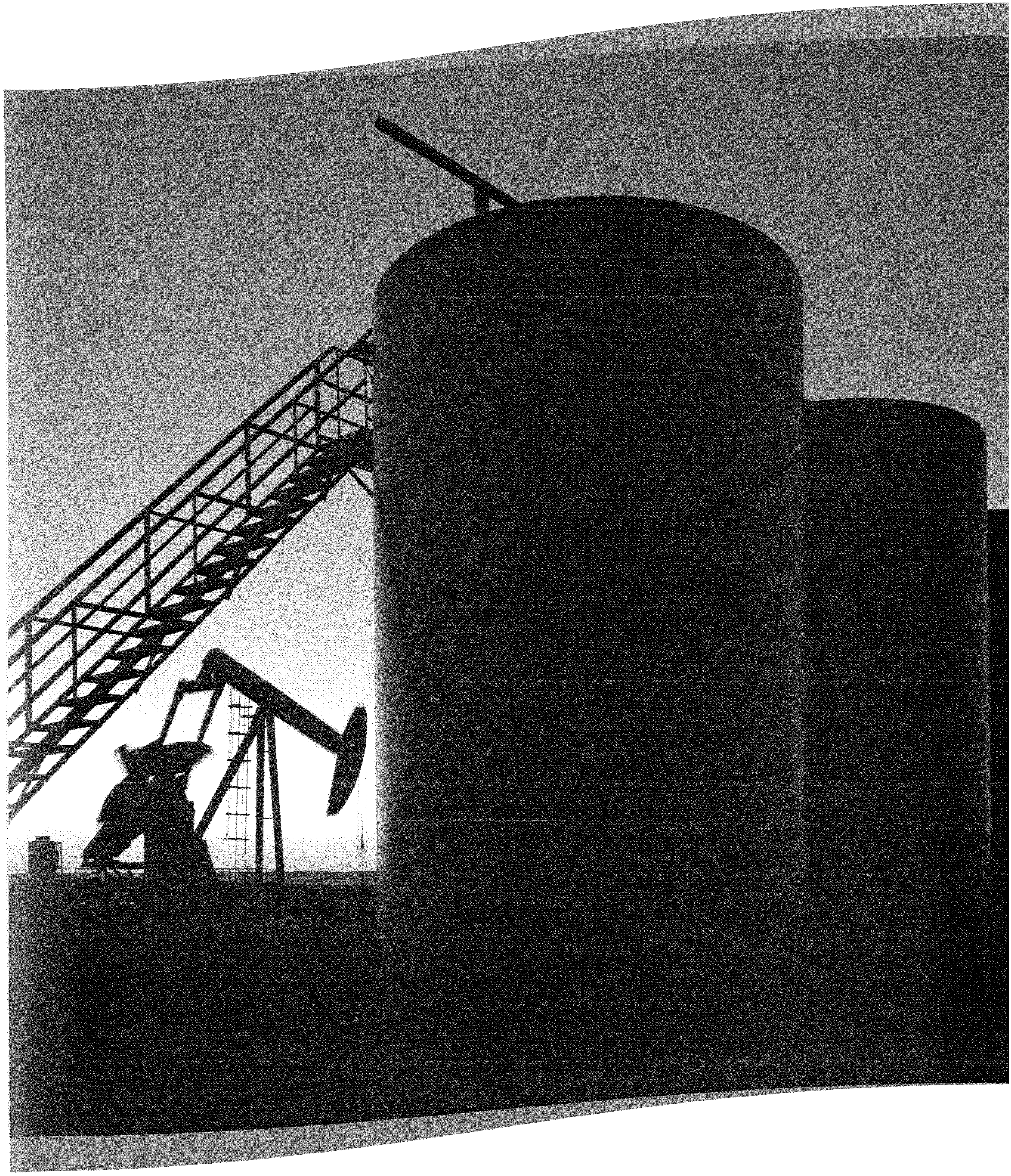
At EOG, we are energized by the challenge of developing new frontiers in horizontal oil.

Mark G. Papa

Mark G. Papa
Chairman and Chief Executive Officer
February 25, 2010

Footnotes

(2) Refer to reconciliation schedule on page 105.




Horn River Basin
CANADA
Wapiti
Highvale
Twining/ Drumheller
Calgary
Shallow Gas Trend
Waskada
Williston Basin
UNITED STATES
Greater Green River Basin
Powder River Basin
Uinta Basin
Denver
Hugoton Deep
Anadarko Basin
Oklahoma City
Fort Worth
Barnett Shale
Permian Basin
Midland
Haynesville-Bossier/ Travis Peak/ Cotton Valley
Tyler
Mississippi Salt Basin
Wilcox - Frio
Houston
Wilcox
Lobo/ Roleta
Corpus Christi
Frio
Gulf of Mexico Shelf
LEGEND
Areas of Operation
Offices
Corporate Headquarters

WORLDWIDE

2009 Production	773 Bcfe
2009 Year-End Proved Reserves	10,776 Bcfe

UNITED STATES

2009 Production	568 Bcfe
2009 Year-End Proved Reserves	8,030 Bcfe

CANADA

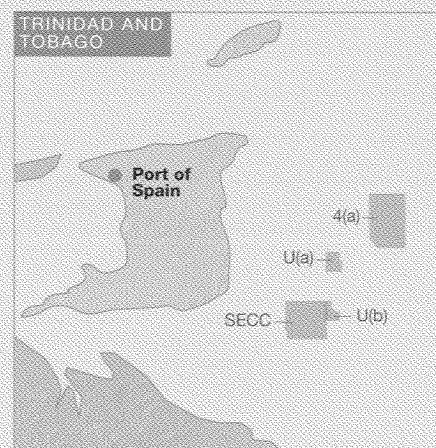
2009 Production	93 Bcfe
2009 Year-End Proved Reserves	1,715 Bcfe

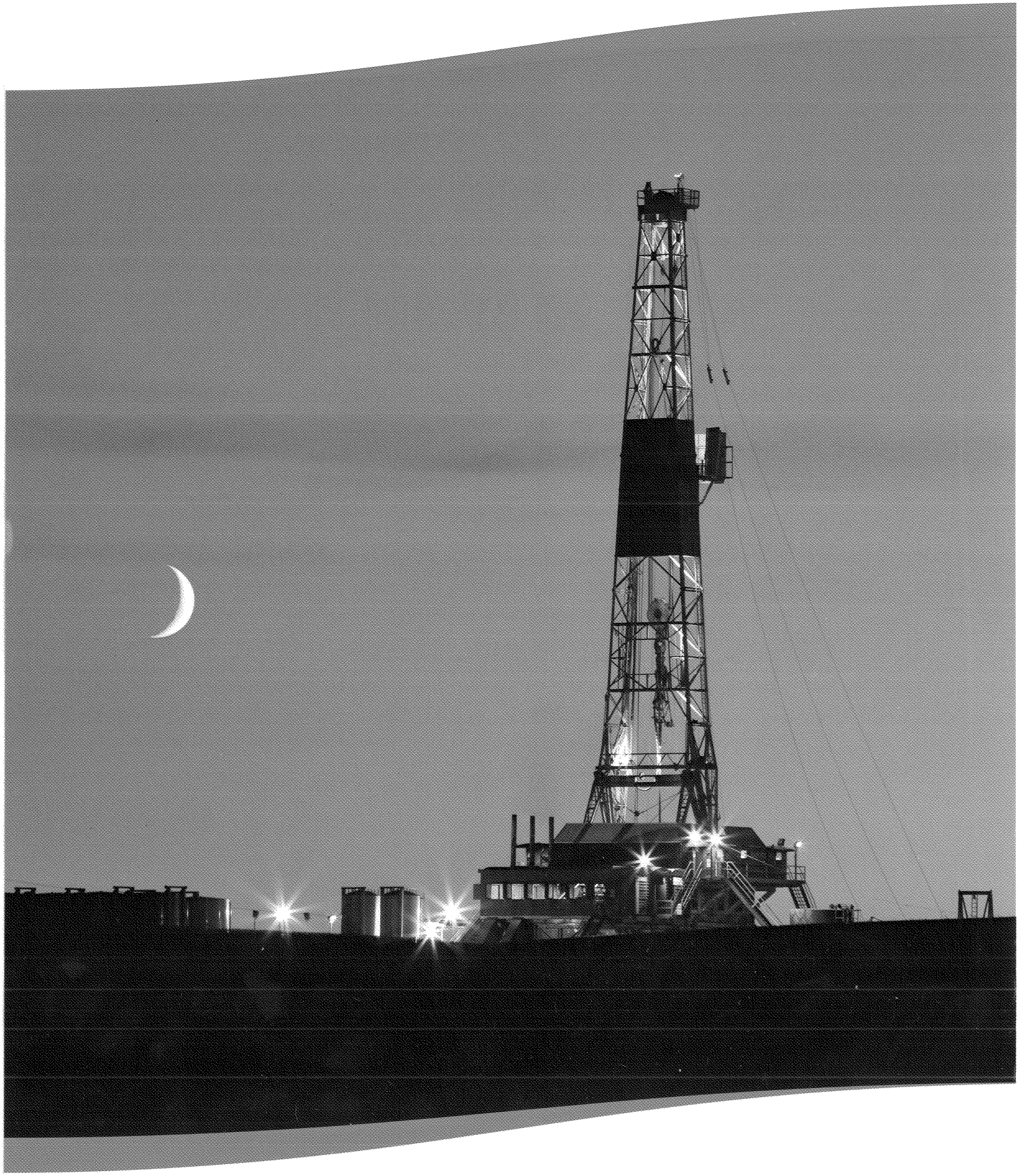
TRINIDAD AND TOBAGO

2009 Production	106 Bcfe
2009 Year-End Proved Reserves	1,018 Bcfe

OTHER INTERNATIONAL

2009 Production	6 Bcfe
2009 Year-End Proved Reserves	13 Bcfe





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

FORM 10-K

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

For the fiscal year ended December 31, 2009

or

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

Commission file number: 1-9743

EOG RESOURCES, INC.

(Exact name of registrant as specified in its charter)

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

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

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
Preferred Share Purchase Rights	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 ☒ No ☐

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 ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ☒ No ☐

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. ☐

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

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

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, 2009: $16,923,094,790.

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, 252,578,053 shares outstanding as of February 19, 2010.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2010 Annual Meeting of Stockholders to be filed within 120 days after December 31, 2009 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

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 natural gas and crude oil primarily in major producing basins in the United States of America (United States), Canada, The Republic of Trinidad and Tobago (Trinidad), the United Kingdom, 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, 2009, EOG's total estimated net proved reserves were 10,776 billion cubic feet equivalent (Bcfe), of which 8,898 billion cubic feet (Bcf) were natural gas reserves and 220 million barrels (MMBbl), or 1,317 Bcfe, were crude oil and condensate reserves and 93 MMBbl, or 561 Bcfe, were natural gas liquids reserves (see Supplemental Information to Consolidated Financial Statements). At such date, approximately 75% of EOG's reserves (on a natural gas equivalent basis) were located in the United States, 16% in Canada and 9% in Trinidad. As of December 31, 2009, EOG employed approximately 2,100 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. 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 (3-D) 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 natural gas and crude oil 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.

At December 31, 2009, 81% of EOG's net proved United States and Canada reserves (on a natural gas equivalent basis) were natural gas and 19% were crude oil and condensate and natural gas liquids. 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 2009 and certain 2010 plans for EOG's United States and Canada operations.

United States. In 2009, EOG completed 116 net gas wells in the Barnett Shale play of the Fort Worth Basin. EOG uses the term Combo wells to refer to wells that derive economic value from crude oil and condensate, natural gas liquids and associated natural gas in relatively equal portions. During 2009, EOG completed 94 net Combo wells in the Barnett Shale play. During the year, EOG's total production from the Barnett Shale play grew to an average net daily rate of 400 million cubic feet per day (MMcfd) of natural gas and 13.1 thousand barrels per day (MBbld) of crude oil and condensate and natural gas liquids. EOG's 2009 liquids production from the Barnett Shale play increased by approximately 97% compared to 2008. For 2010, EOG plans to drill approximately 234 net Barnett Shale Combo wells. Primary 2010 growth for EOG in the Barnett Shale will be provided by crude oil and natural gas liquids. During the third quarter of 2009, EOG acquired certain crude oil and natural gas properties and related assets in the Barnett Shale consisting of proved developed and undeveloped reserves and approximately 33,000 net unproved acres. With a total of approximately 840,000 net acres, EOG is one of the largest leaseholders in the Barnett Shale play, providing EOG with long-term reserve and production growth potential for years to come.

Throughout the Rocky Mountain area, EOG expanded its acreage position with the addition of prospective crude oil acreage in 2009. EOG now holds approximately 1.5 million net acres in the Rocky Mountain area, including over 500,000 net acres throughout the Williston Basin of North Dakota and Montana available for exploration in the Bakken and Three Forks plays. In addition, EOG also holds acreage in the Rocky Mountain area relating to certain potential exploration and development prospects which EOG is currently evaluating. During 2009, EOG drilled 106 net wells in the Uinta Basin, Utah, and 57 net wells in the Williston Basin. Production from the Rocky Mountain area increased 14% primarily through increased liquids production. The net average production for 2009 was 240 MMcfd of natural gas and 34.7 MBbld of crude oil and condensate and natural gas liquids. In December 2009, EOG and a third party exchanged certain natural gas related properties in the Rocky Mountain area. In 2010, EOG intends to increase its activity level in the Bakken and Three Forks plays in the Williston Basin by drilling over 95 net wells. EOG will have limited drilling activity on its core natural gas assets within the Rocky Mountain area and will primarily focus on exploiting and expanding the oil resource plays.

In 2009, 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 76 MMcfd of natural gas and 5.3 MBbld of crude oil and condensate and natural gas liquids. Total crude oil and condensate and natural gas liquids volumes increased 15% in 2009 compared to 2008. In Southwest Kansas, EOG continued its active drilling program focused on high potential Morrow and St. Louis targets 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 its successful horizontal exploitation of the Cleveland sandstone, drilling 13 net wells with per well initial production rates of approximately 500 barrels of oil per day. Since 2002, EOG has drilled over 200 net wells in this play and holds approximately 65,000 acres throughout the trend. EOG significantly expanded its acreage position in the Western Anadarko Basin during 2009 with the addition of over 100,000 net acres focused on the extension of core plays, as well as multiple new liquids-rich plays which will be exploited in 2010 and beyond. EOG holds approximately 580,000 net acres in the Mid-Continent area.

In the South Texas area, EOG experienced continued success in 2009, drilling 54 net wells. During 2009, net production averaged 204 MMcfd of natural gas and 7.5 MBbld of crude oil and condensate and natural gas liquids. EOG's activity was focused in Webb, Zapata, San Patricio, Duval and Matagorda counties, where EOG drilled successful wells in the Lobo, Roleta, Frio and Wilcox trends. EOG continued to focus on horizontal drilling, targeting the Perdido, Wilcox and Lobo sands. EOG also continued directional drilling under Nueces Bay. EOG drilled a deeper pool wildcat discovery under Indian Point, along with additional development drilling, with seven wells drilled yielding over 34 Bcfe net proved reserves. EOG plans to significantly increase drilling activity in the South Texas area in 2010. Approximately 168 net wells are planned during 2010 for South Texas. EOG holds approximately 600,000 net acres in the South Texas area. In addition, EOG holds acreage in the South Texas area relating to certain potential exploration and development prospects which EOG is currently evaluating.

Also during 2009, EOG participated in 25 net wells and implemented five Wolfcamp waterfloods in the Permian Basin area. The wells drilled throughout the Permian Basin tested the Bone Spring, Wolfcamp, Permo-Penn and other objectives. Production for the year averaged approximately 69 MMcfd of natural gas and 7.1 MBbld of crude oil and condensate and natural gas liquids. EOG acquired approximately 230 square miles of 3-D data and added 100,000 net acres during 2009. EOG holds approximately 490,000 net acres throughout the Permian Basin area. In 2010, EOG plans to continue the development of existing Permian Basin plays, acquire acreage positions in new plays and test new play concepts.

In the Upper Gulf Coast area, EOG averaged 144 MMcfd of natural gas and 2.8 MBbld of crude oil and condensate and natural gas liquids production in 2009. EOG drilled 31 net wells with 10 net wells being Travis Peak vertical stacked pays and Cotton Valley horizontal development wells located in East Texas and North Louisiana. A major growth driver for EOG in this area is the expanded Haynesville and Bossier Shale program that has grown from drilling two wells in late 2008 to 13 wells in 2009. EOG expects to drill 48 net Haynesville and Bossier Shale wells in 2010 on the 159,000 net acres held in the play. Mississippi development focused on a combined crude oil and natural gas discovery at Mechanicsburg Field, where EOG drilled eight wells. In the fourth quarter of 2009, EOG acquired 39,500 net unproved acres in Nacogdoches County, Texas, within the Haynesville and Bossier Shale formations and expects to acquire up to an additional 7,500 net acres as part of the same transaction during the first quarter of 2010. EOG holds approximately 370,000 net acres in the Upper Gulf Coast area.

During 2009, EOG continued the development of its Pennsylvania Marcellus Shale acreage, drilling a total of three gross vertical and 17 gross horizontal wells (13 net wells). Nine of the wells have been completed with most of those awaiting final construction of gas gathering system infrastructure to commence sales. The gas gathering systems being constructed by EOG should be completed by the end of the first quarter of 2010. Several wells tested at 24-hour rates in excess of 5 MMcfd. In 2010, EOG will continue to develop the Marcellus Shale, drilling an estimated 25 to 30 net wells. Most of the wells will be in the Seneca Joint Venture area in Clearfield, Elk and McKean Counties, Pennsylvania, where EOG holds a 50% working interest. Several wells are also planned for Bradford County, Pennsylvania, where EOG holds a 100% working interest. EOG currently holds approximately 225,000 net acres in the Pennsylvania Marcellus Shale.

At December 31, 2009, EOG held approximately 4,185,000 net undeveloped acres in the United States.

During 2009, EOG continued the expansion of its gathering and processing activities in the Barnett Shale play of North Texas and the Bakken play of North Dakota. In 2009, EOG placed into operation one 40 MMcfd natural gas processing plant in the Barnett Combo play of North Texas, and began construction of a second 40 MMcfd processing unit which is expected to begin operation during the second quarter of 2010. EOG also expanded its gathering system in the Barnett Combo play to transport production to its processing plant and continued expansion of its gathering system in the Bakken play.

In the North Dakota Bakken play, EOG constructed and placed in service during February 2010 a 76-mile, 12-inch diameter "dense phase" natural gas gathering pipeline connecting its Stanley, North Dakota, gathering system with the Alliance Pipeline, near Upham, North Dakota. The Alliance Pipeline transports natural gas to the Chicago, Illinois, area. EOG also replaced its 20 MMcfd natural gas liquids processing plant, located near Stanley, North Dakota, with an 80 MMcfd refrigeration oil/condensate removal plant. In combination, these projects will allow EOG to more efficiently transport the associated natural gas and natural gas liquids production from its Bakken oil wells. At year-end 2009, the combined throughput of these systems was 15 MMcfd of natural gas.

Additionally, in support of its operations in the Bakken play, EOG constructed a crude oil loading facility near Stanley, North Dakota, designed to load crude oil into 100-car unit trains for transport to Stroud, Oklahoma. At Stroud, Oklahoma, EOG constructed a crude oil offloading facility and a pipeline to transport the crude oil to the Cushing, Oklahoma, trading hub. The first shipment of crude oil through these facilities occurred at year-end 2009. When fully operational, the capacity of these facilities is expected to allow transport of approximately 60,000 barrels per day of Bakken crude oil.

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 70 miles of 8-inch, 10-inch and 20-inch diameter pipe, while the North Dakota system totals 290 miles of 8-inch and 12-inch pipe.

Canada. EOG conducts operations through its subsidiary, EOG Resources Canada Inc. (EOGRC), from offices in Calgary, Alberta. During 2009, EOGRC departed from its historical vertical shallow natural gas drilling program to focus on bigger target horizontal gas growth in the Horn River Basin and horizontal crude oil growth within existing legacy fields, mainly in Waskada, Manitoba and Highvale, Alberta. During 2009, EOGRC drilled or participated in 98 net wells, 60 of which were horizontal wells and 38 of which were vertical wells. Correspondingly, net crude oil and condensate and natural gas liquids production increased by 41% to 5.2 MBbld and natural gas production increased 1% to 224 MMcfd due to this shift in focus. The horizontal production growth strategy will continue in 2010 with 12 net horizontal gas wells planned in the Horn River Basin and 120 net horizontal oil wells planned in Waskada and other projects. EOGRC acquired 530,000 net acres during the economic downturn in 2009 which will set up numerous exploration and development opportunities in 2010 and beyond.

At December 31, 2009, EOGRC held approximately 1,660,000 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 those 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 in late January 2010 that is expected to begin producing by the end of the first quarter of 2010. In Block 4(a), EOG installed offshore facilities and plans to drill development wells to supply natural gas under a contract with the National Gas Company of Trinidad and Tobago (NGC) if the North Eastern Offshore (NEO) pipeline is installed by NGC. The NEO pipeline has not been completed, and EOG plans to source 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 2009, EOG recognized equity income of $0.5 million and received cash dividends of $3 million from CNCL and recognized equity income of $3 million and received cash dividends of $4 million from N2000.

Natural gas from EOG's Trinidad operations currently is sold to NGC or its subsidiary. Crude oil and condensate from EOG's Trinidad operations currently is sold to the Petroleum Company of Trinidad and Tobago.

In 2009, EOG's average net production from Trinidad was 273 MMcfd of natural gas and 3.1 MBbld of crude oil and condensate.

At December 31, 2009, EOG held approximately 156,000 net undeveloped acres in Trinidad.

United Kingdom. In 2002, EOG's subsidiary, EOG Resources United Kingdom Limited (EOGUK), acquired a 25% non-operating working interest in a portion of Block 49/16, located in the Southern Gas Basin of the North Sea. In August 2004, production commenced in the Valkyrie field in the Southern Gas Basin.

In 2003, EOGUK acquired 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. Since November 2003, three successful exploratory wells have been drilled in the Arthur field, with production commencing in January 2005. There is currently one remaining producing well in the Arthur field and this well is expected to cease production during the first half of 2010.

In 2006, EOGUK participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. 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 United Kingdom (U.K.) Department of Energy and Climate Change during the second quarter of 2010 and anticipates receiving approval of this plan in late 2010. The operator and partners are currently evaluating an export route for production from the project.

During the third quarter of 2009, EOG completed a farm-in agreement with owners of the Central North Sea Block 15/30a Area AB. In December 2009, EOG, as operator, drilled an exploratory well on this prospect, which was declared a dry hole in January 2010.

During the second quarter of 2009, EOGUK drilled two exploratory wells in the East Irish Sea. Well 110/14b-7, in which EOGUK has a 70% working interest, was a dry hole while well 110/12-6, in which EOGUK has 100% working interest, was an oil discovery and was designated the Conwy field. Engineering studies were initiated with an intent to submit a field development plan to the U.K. Department of Energy and Climate Change during the first quarter of 2010. A rig has been contracted and has begun drilling two further exploratory wells offsetting the Conwy field. The first of the wells was declared a dry hole in February 2010. Results are expected for the second well by the end of the first quarter of 2010. The licenses for the East Irish Sea were awarded to EOGUK in 2007.

In 2009, production averaged 7 MMcfd of natural gas, net, in the United Kingdom.

At December 31, 2009, EOG held approximately 277,000 net undeveloped acres in the United Kingdom.

China. In July 2008, EOG acquired rights from ConocoPhillips in a Petroleum Contract covering the Chuanzhong Block exploration area in the Sichuan Basin, Sichuan Province, China. In October 2008, EOG obtained the rights to shallower zones on the acreage acquired.

During the second quarter of 2009, EOG completed a monitoring well and in the third quarter of 2009, drilled a horizontal well, which will be completed and tested during the first quarter of 2010. During the third quarter of 2009, EOG drilled a second monitoring well to evaluate one of the shallower zones and is currently drilling a second horizontal well that is expected to be completed during the third quarter of 2010.

In 2009, production averaged 8 million cubic feet equivalent per day of natural gas, net, in China.

At December 31, 2009, EOG held approximately 130,000 net acres in China.

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

Marketing

Wellhead Marketing. In 2009, 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 2010, the pricing mechanism for such production is expected to remain the same.

In 2009, 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 is expected to remain the same in 2010.

In 2009, over 90% of the wellhead natural gas volumes from the United Kingdom were sold on the spot market. The remaining volumes were sold by means of forward contracts. The 2010 marketing strategy for the wellhead natural gas volumes in the United Kingdom is to sell all natural gas on the spot market.

In 2009, 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 2010.

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

During 2009, no single purchaser accounted for 10% or more of EOG's natural gas, crude oil and condensate and natural gas liquids revenues. EOG does not believe that the loss of any single purchaser would have a material adverse effect on its financial condition or results of operations.

Wellhead Volumes and Prices

The following table sets forth certain information regarding EOG's wellhead volumes of, and average prices for, natural gas per thousand cubic feet (Mcf), crude oil and condensate per barrel (Bbl) and natural gas liquids per Bbl. The table also presents natural gas equivalent volumes which are determined using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil and condensate or natural gas liquids for each of the years ended December 31, 2009, 2008 and 2007.

Year Ended December 31	**2009**	**2008**	**2007**
Natural Gas Volumes (MMcfd) [(1)]			
United States	1,134	1,162	971
Canada	224	222	224
Trinidad	273	218	252
Other International [(2)]	14	17	23
Total	**1,645**	**1,619**	**1,470**
Crude Oil and Condensate Volumes (MBbld) [(1)]			
United States	47.9	39.5	24.6
Canada	4.1	2.7	2.4
Trinidad	3.1	3.2	4.1
Other International [(2)]	0.1	0.1	0.1
Total	**55.2**	**45.5**	**31.2**
Natural Gas Liquids Volumes (MBbld) [(1)]			
United States	22.5	15.0	11.1
Canada	1.1	1.0	1.1
Total	**23.6**	**16.0**	**12.2**
Natural Gas Equivalent Volumes (MMcfed) [(3)]			
United States	1,556	1,490	1,184
Canada	256	244	245
Trinidad	291	237	276
Other International [(2)]	15	17	24
Total	**2,118**	**1,988**	**1,729**
Total Bcfe [(3)]	**773.0**	**727.6**	**631.3**
Average Natural Gas Prices ($/Mcf) [(4)]			
United States	$ 3.72	$ 8.22	$ 6.27
Canada	3.85	7.64	6.25
Trinidad	1.73	3.58	2.71
Other International [(2)]	4.34	8.18	6.19
Composite	**3.42**	**7.51**	**5.65**
Average Crude Oil and Condensate Prices ($/Bbl) [(4)]			
United States	$ 54.42	$ 87.68	$ 68.85
Canada	57.72	89.70	65.27
Trinidad	50.85	92.90	69.84
Other International [(2)]	53.07	99.30	66.84
Composite	**54.46**	**88.18**	**68.69**
Average Natural Gas Liquids Prices ($/Bbl) [(4)]			
United States	$ 30.03	$ 53.33	$ 47.63
Canada	30.49	54.77	44.54
Composite	**30.05**	**53.42**	**47.36**

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(3) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil and condensate and natural gas liquids.
(4) Dollars per thousand cubic feet or per barrel, as applicable.

Competition

EOG competes with major integrated 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 personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market natural gas and crude oil. 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 natural gas and crude oil, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. EOG also faces competition from competing energy sources, such as liquefied natural gas imported into the United States from other countries, and, to a lesser extent, alternative energy sources.

Regulation

United States Regulation of Natural Gas and Crude Oil Production. Natural gas and crude oil production operations are subject to various types of regulation, including regulation in the United States by state and federal 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 Minerals Management Service (MMS), 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 MMS.

BLM and MMS 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 MMS). Such offshore operations are subject to numerous regulatory requirements, including the need for prior MMS 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 MMS 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 less regulated approach currently being followed by the FERC will continue indefinitely.

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 natural gas and crude oil 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 United States Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions.

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.

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. EOG is unable to predict the timing, scope and effect of any such proposed laws, regulations and treaties, 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 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 will continue to review the risks to its business and operations associated with all environmental matters, including climate change. In addition, EOG will continue to monitor and assess any new policies, legislation or regulations in the areas where it operates to determine the impact on its operations and take appropriate actions, where necessary.

Canadian Regulation of Natural Gas and Crude Oil 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 prices, taxes, 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 natural gas and crude oil 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.

The Alberta Government implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional crude oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional crude oil range from 0% to 50% and natural gas royalty rates range from 5% to 50%.

The Deep Oil Exploration Program (DOEP) and the Natural Gas Deep Drilling Program (NGDDP) are new programs that began January 1, 2009 in Alberta. These programs provide upfront royalty adjustments to new wells. To qualify for royalty adjustments under the DOEP, exploratory oil wells must have a vertical depth greater than 2,000 meters with a government interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first 1,000,000 Canadian dollars of royalty or the first 12 months of production, whichever comes first. The NGDDP applies to natural gas wells producing at a vertical depth greater than 2,500 meters. The NGDDP will have an escalating royalty credit in line with progressively deeper wells from 625 Canadian dollars per meter to a maximum of 3,750 Canadian dollars per meter. There are additional benefits for the deepest wells. Both the DOEP and the NGDDP are five-year programs. Any wells spudded after December 31, 2013, or any wells for which EOG chooses the transition option described below, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018.

In November 2008, the Alberta Government announced that companies drilling new natural gas and conventional crude oil wells at depths between 1,000 and 3,500 meters, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The election is made prior to the end of the first calendar month in which the commodity is produced. All wells using the transitional royalty rates must shift to the new royalty framework rates on January 1, 2014.

EOG expects these regulations of the Alberta Government to have a marginally positive impact on EOG's financial condition and results of operations.

Environmental Regulation - Canada. All phases of the oil and gas industry in Canada are subject to environmental regulation pursuant to a variety of Canadian federal, provincial and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances 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 regulate industrial emissions of GHG and air pollutants from a broad range of industrial sectors in the Regulatory Framework for Air Emissions released April 2007 and updated in a March 2008 document entitled Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions (collectively, Federal Plan). The Federal Plan outlines proposed policies to reduce the emissions of GHG and air pollutants by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations could come into effect as early as 2010 and targets are expected to be based on percentages rather than absolute reductions. EOG is also aware of legislation proposed by the Canadian legislature to reduce GHG emissions as well as proposed regulations that would establish a credit emissions trading system in Canada. Additionally, 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.

EOG is unable to predict the timing, scope and effect of any such proposed laws, regulations and treaties, but the direct and indirect costs of such enacted laws, regulations and treaties and, if enacted, proposed laws, regulations and treaties, could materially and adversely affect EOG's business, results of operations, financial condition and competitive position.

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.

Other Matters

Energy Prices. Since EOG is primarily a natural gas producer, it is more significantly impacted by changes in natural gas prices than changes in prices for crude oil and condensate or natural gas liquids. 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 54% decrease in the average wellhead natural gas price for production in the United States and Canada received by EOG from 2008 to 2009, an increase of 30% from 2007 to 2008, and a decrease of 4% from 2006 to 2007. The average New York Mercantile Exchange (NYMEX) natural gas strip price for 2010 has decreased approximately 9% subsequent to December 31, 2009. Crude oil and condensate and natural gas liquids production comprised a larger portion of EOG's production mix in 2009 than in prior years and is expected to comprise an even larger portion in 2010. Average crude oil and condensate prices received by EOG for production in the United States decreased by 38% in 2009, increased by 27% in 2008 and increased by 10% in 2007, each as compared to the immediately preceding year. The average NYMEX crude oil strip price for 2010 has declined approximately 1% subsequent to December 31, 2009. 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 natural gas, crude oil and condensate, natural gas liquids, ammonia and methanol prices in the future. For additional discussion regarding changes in natural gas and crude oil prices and the risks that such changes may present to EOG, see ITEM 1A. Risk Factors.

Including the impact of EOG's 2010 natural gas hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2010 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $30 million for net income and $45 million for cash flows from operating activities. EOG's price sensitivity in 2010 for each $1.00 per barrel change in wellhead crude oil and condensate price, combined with the related change in natural gas liquids price, is approximately $22 million for net income and $33 million for cash flows from operating activities. For information regarding EOG's natural gas hedge position as of December 31, 2009, 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 natural gas and crude oil. 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, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions.

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

In addition, EOG's operations outside of the United States are subject to certain risks, including expropriation of assets, risks of increases in taxes and government royalties, unilateral or forced renegotiation of contracts with foreign governments, political instability, payment delays, limits on allowable levels of production and currency exchange and repatriation losses, as well as changes in laws, regulations and policies governing operations of foreign companies. 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 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 25, 2010) are as follows:

Name	Age	Position
Mark G. Papa	63	Chairman of the Board and Chief Executive Officer; Director
Loren M. Leiker	56	Senior Executive Vice President, Exploration
Gary L. Thomas	60	Senior Executive Vice President, Operations
Robert K. Garrison	57	Executive Vice President, Exploration
Fredrick J. Plaeger, II	56	Senior Vice President and General Counsel
Timothy K. Driggers	48	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.

Robert K. Garrison was elected Executive Vice President, Exploration in February 2007. He was elected Senior Vice President and General Manager of EOG's Corpus Christi, Texas office in August 2004 and, prior to such election, was Vice President and General Manger of EOG's Corpus Christi, Texas office. Mr. Garrison joined EOG in April 1995.

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 and accounting 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 in this report, including the consolidated financial statements and the related notes.

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

Prices for natural gas and crude oil fluctuate widely. Since we are primarily a natural gas company, we are more significantly affected by changes in natural gas prices than changes in the prices for crude oil and condensate or natural gas liquids. Among the factors that can cause these price fluctuations are:

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

Our cash flow and results of operations depend to a great extent on the prevailing prices for natural gas and crude oil. Prolonged or substantial declines in natural gas and/or crude oil 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 natural gas and crude oil prices in the future such that the future cash flow from our natural gas and crude oil properties falls below the net book value of our properties, we may be required to write down the value of our natural gas and crude oil 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 natural gas and crude oil wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling natural gas and crude oil wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive natural gas and crude oil 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 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 and related facilities and equipment to gather, process, compress, transport and market natural gas, crude oil and related commodities;
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and other necessary equipment; and
- lack of necessary services and/or qualified personnel.

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

The sale of our natural gas and crude oil 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 natural gas and crude oil 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 natural gas and crude oil at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves, as is, in turn, 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, financial condition and competitive position.

Specifically, as an owner or lessee and operator of natural gas and crude oil 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 Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions. Changes in, or additions to, these regulations could materially and adversely affect our business, results of operations, financial condition and competitive position.

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 United States (U.S.) lawmakers and by the Canadian legislature to reduce GHG emissions. We will continue to monitor and assess any new policies, legislation or regulations 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 such proposed laws, regulations and 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, financial condition and competitive position.

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

A portion of our natural gas and crude oil 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 natural gas or crude oil 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 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 may include, among other risks:

- loss of revenue, equipment and property as a result of expropriation, acts of terrorism, war, civil unrest and other political risks;
- increases in taxes and governmental royalties;
- 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;
- changes in laws and policies governing operations of foreign-based companies; 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 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 natural gas and crude oil 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 natural gas and crude oil properties. Although we perform reviews of properties to be acquired in a manner that we believe is 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 natural gas and crude oil reserves, 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.

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

Demand for natural gas and crude oil 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 and changes in weather patterns, such as hurricanes in the Gulf of Mexico and increases in storm intensity, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions and changes in weather patterns 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.

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, development, production, exploration and abandonment of natural gas and crude oil 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 natural gas and crude oil 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 natural gas and crude oil 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 rise 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 natural gas, crude oil 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 weak. In addition, there continues to be weakness and volatility in domestic and global financial markets, including the credit crisis 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 natural gas, crude oil 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 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 personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market natural gas and crude oil. 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 natural gas and crude oil, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. We also face competition from competing energy sources, such as liquefied natural gas imported into the U.S. from other countries and, to a lesser extent, 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 natural gas and liquids 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 natural gas and liquids 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.

Our hedging activities may prevent us from benefiting fully from increases in natural gas and crude oil 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 natural gas and crude oil 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 natural gas and crude oil 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 do not insure against all potential losses and could be materially and adversely affected by unexpected liabilities.

The exploration for, and production of, natural gas and crude oil 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 would reduce the funds available to us for our exploration, 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, 2009, approximately 9% of our 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 natural gas and crude oil 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.

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 natural gas and liquids, including crude oil and condensate and natural gas liquids, 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 natural gas, crude oil and condensate and natural gas liquids 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 natural gas and crude oil 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. Volumes 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, 2009. 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	1,724,004	1,245,914	5,908,475	4,185,139	7,632,479	5,431,053
Canada	1,961,930	1,670,948	1,736,290	1,660,279	3,698,220	3,331,227
Trinidad	72,901	64,286	165,427	155,723	238,328	220,009
United Kingdom	10,230	2,946	472,950	276,583	483,180	279,529
China	130,546	130,546	-	-	130,546	130,546
Total	3,899,611	3,114,640	8,283,142	6,277,724	12,182,753	9,392,364

Producing Well Summary. The following table reflects EOG's ownership in producing natural gas and crude oil wells located in the United States, Canada, Trinidad, the United Kingdom and China at December 31, 2009. Gross natural gas and crude oil wells include 2,399 wells with multiple completions.

	Productive Wells	
	Gross	**Net**
Natural Gas	21,495	18,244
Crude Oil	2,260	1,574
Total	23,755	19,818

Drilling and Acquisition Activities. During the years ended December 31, 2009, 2008 and 2007, EOG expended $3.9 billion, $5.1 billion and $3.6 billion, respectively, for exploratory and development drilling and acquisition of leases and producing properties, including asset retirement obligations of $84 million, $181 million and $31 million, respectively. EOG drilled, participated in the drilling of or acquired wells as set out in the table below for the periods indicated:

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Completed						
United States and Canada						
Gas	467	399	1,498	1,261	1,747	1,441
Oil	233	181	223	171	98	86
Dry	26	22	50	47	59	52
Total	726	602	1,771	1,479	1,904	1,579
Outside United States and Canada						
Gas	-	-	-	-	6	5
Oil	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	-	-	-	-	6	5
Total Development	726	602	1,771	1,479	1,910	1,584
Exploratory Wells Completed						
United States and Canada						
Gas	23	17	44	38	62	54
Oil	25	17	37	19	14	12
Dry	7	6	9	9	18	16
Total	55	40	90	66	94	82
Outside United States and Canada						
Gas	-	-	-	-	-	-
Oil	1	1	-	-	-	-
Dry	1	1	-	-	2	1
Total	2	2	-	-	2	1
Total Exploratory	57	42	90	66	96	83
Total	783	644	1,861	1,545	2,006	1,667
Wells in Progress at end of period	288	248	223	191	223	195
Total	1,071	892	2,084	1,736	2,229	1,862
Wells Acquired (1)						
Gas	581	244	102	94	41	15
Oil	133	126	9	7	-	-
Total	714	370	111	101	41	15

(1) Includes the acquisition of additional interests in certain wells in which EOG previously owned an interest.

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 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.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the fourth quarter of 2009.

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
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
2008			
First Quarter	$ 129.90	$ 77.18	$ 0.120
Second Quarter	144.99	117.76	0.120
Third Quarter	133.89	79.80	0.135
Fourth Quarter	90.80	54.42	0.135

On February 9, 2010, EOG's Board of Directors (Board) increased the quarterly cash dividend on the common stock from the current $0.145 per share to $0.155 per share effective beginning with the dividend to be paid on April 30, 2010.

As of February 15, 2010, there were approximately 1,700 record holders and approximately 210,000 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, 2009 - October 31, 2009	3,752	$89.49	-	6,386,200
November 1, 2009 - November 30, 2009	4,403	88.51	-	6,386,200
December 1, 2009 - December 31, 2009	3,960	93.89	-	6,386,200
Total	12,115	90.57		

(1) The 12,115 total shares for the quarter ended December 31, 2009 and the 167,867 shares for the full year 2009 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 2009, EOG did not repurchase any shares under the Board-authorized repurchase program.

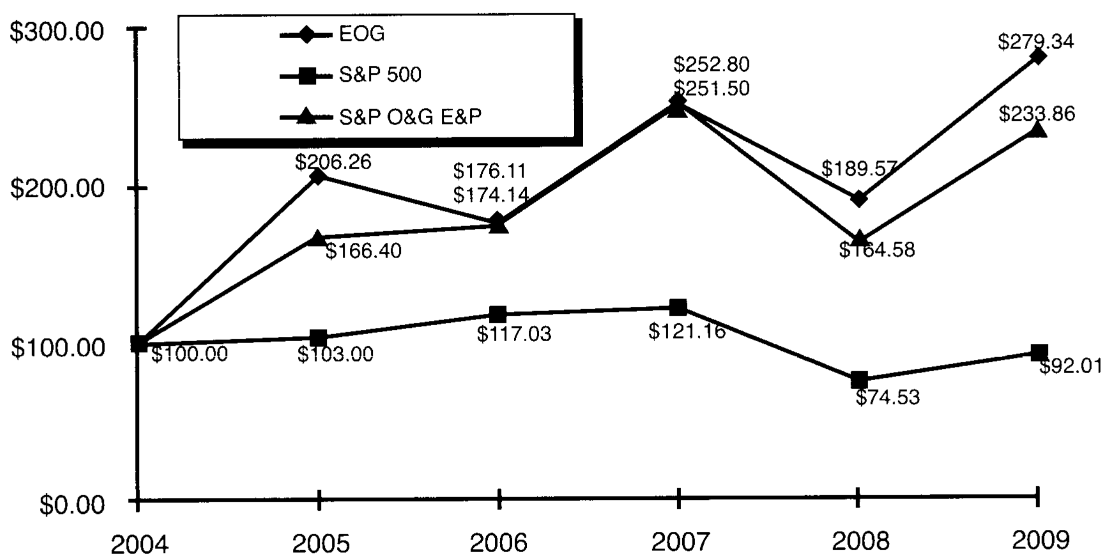
Comparative Stock Performance

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, 2004 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, 2009)



*Cumulative total return assumes reinvestment of dividends.

	2004	2005	2006	2007	2008	2009
EOG	$100.00	$206.26	$176.11	$252.80	$189.57	$279.34
S&P 500	$100.00	$103.00	$117.03	$121.16	$ 74.53	$ 92.01
S&P O&G E&P	$100.00	$166.40	$174.14	$251.50	$164.58	$233.86

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

Year Ended December 31	2009	2008	2007	2006	2005
Statement of Income Data:					
Net Operating Revenues	$ 4,786,959	$ 7,127,143	$ 4,239,303	$ 3,928,641	$ 3,671,243
Operating Income	$ 970,841	$ 3,767,185	$ 1,648,396	$ 1,903,553	$ 2,004,631
Net Income	$ 546,627	$ 2,436,919	$ 1,089,918	$ 1,299,885	$ 1,259,576
Preferred Stock Dividends	-	443	6,663	10,995	7,432
Net Income Available to Common Stockholders	$ 546,627	$ 2,436,476	$ 1,083,255	$ 1,288,890	$ 1,252,144
Net Income Per Share Available to Common Stockholders					
Basic	$ 2.20	$ 9.88	$ 4.45	$ 5.33	$ 5.24
Diluted	$ 2.17	$ 9.72	$ 4.37	$ 5.24	$ 5.13
Dividends Per Common Share	$ 0.58	$ 0.51	$ 0.36	$ 0.24	$ 0.16
Average Number of Common Shares					
Basic	248,996	246,662	243,469	241,782	238,797
Diluted	251,884	250,542	247,637	246,100	243,975

At December 31	2009	2008	2007	2006	2005
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$ 16,139,225	$ 13,657,302	$ 10,429,254	$ 7,944,047	$ 6,087,179
Total Assets	18,118,667	15,951,226	12,088,907	9,402,160	7,753,320
Long-Term Debt and Current Portion of Long-Term Debt	2,797,000	1,897,000	1,185,000	733,442	985,067
Total Stockholders' Equity	9,998,042	9,014,497	6,990,094	5,599,671	4,316,292

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) 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. 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 2009 totaled $547 million as compared to $2,436 million for 2008. At December 31, 2009, EOG's total estimated net proved reserves were 10.8 trillion cubic feet equivalent, an increase of 2,087 billion cubic feet equivalent (Bcfe) from December 31, 2008.

Operations

Several important developments have occurred since January 1, 2009.

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 natural gas and crude oil production. In Canada, EOG departed from its historical vertical shallow natural gas drilling program to focus on bigger target horizontal gas growth in the Horn River Basin and horizontal 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 86% of total company production in 2009 as compared to 87% in 2008. In 2009, the Fort Worth Basin Barnett Shale and North Dakota Bakken areas produced an increasing amount of crude oil and condensate and natural gas liquids. For 2009, crude oil and condensate and natural gas liquids production accounted for approximately 22% of total company production as compared to 19% for 2008. Based on current trends, EOG expects its 2010 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 2009. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

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 approximately 33,000 net unproved acres. Production from these assets averaged approximately 2,300 barrels of oil equivalent per day, net, at the time of acquisition. The aggregate purchase price of the transactions totaled $196.7 million, consisting of cash consideration of $107.1 million and 1,450,000 shares of EOG common stock valued at $89.6 million on the closing date of the applicable transaction.

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 39,500 net unproved acres 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 Business Combinations Topic of the Accounting Standards Codification (ASC) and has included such amount in Other Liabilities on the Consolidated Balance Sheets. The fair value of such contingent consideration was $35.3 million at December 31, 2009. The aggregate consideration recorded in 2009 for the acquisition of the Haynesville Assets was $134 million, including the contingent consideration. Additionally, EOG expects to acquire up to an additional 7,500 net acres at a final closing expected to occur in the first quarter of 2010. The total price for the Haynesville Assets will not exceed $165 million.

In November 2009, EOG entered into an agreement to sell its crude oil and natural gas related assets located in California for cash consideration of $202 million, subject to customary adjustments under the agreement. The assets sold included approximately 80 wells that accounted for less than 1% of EOG's total 2009 production. The transaction closed on December 10, 2009. EOG realized a pretax gain of $146 million on the sale.

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 provisions of the Business Combinations Topic of the ASC, 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.

In support of its operations in the North Dakota Bakken play, EOG constructed a crude oil loading facility near Stanley, North Dakota, designed to load crude oil into 100-car unit trains for transport to Stroud, Oklahoma. At Stroud, Oklahoma, EOG constructed a crude oil offloading facility and a pipeline to transport the crude oil to the Cushing, Oklahoma, trading hub. The first shipment of crude oil through these facilities occurred at year-end 2009. When fully operational, the capacity of these facilities is expected to allow transport of approximately 60,000 barrels per day of Bakken crude oil.

International. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. In the Pelican Field, EOG drilled a successful exploratory well in late January 2010 that is expected to begin producing by the end of the first quarter of 2010.

In the United Kingdom, EOG has ongoing production from the Valkyrie and Arthur fields in the Southern Gas Basin of the North Sea Block 23/16f. There is currently one producing well in the Arthur field, and such well is expected to cease production during the first half of 2010. The operator and partners of the non-EOG operated Columbus discovery in the Central North Sea are continuing to evaluate export routes for future production. In addition, the operator expects to submit a revised field development plan to the United Kingdom Department of Energy and Climate Change during the second quarter of 2010 and anticipates receiving approval in late 2010.

During the third quarter of 2009, EOG completed a farm-in agreement with the owners of the Central North Sea Block 15/30a Area AB. In December 2009, EOG began drilling an exploratory well on this prospect. The well was declared a dry hole in January 2010.

EOG continues to expand its exploration prospect portfolio in the United Kingdom. During the second quarter of 2009, EOG drilled two exploratory wells in the East Irish Sea. Well 110/14b-7, in which EOG has a 70% working interest, was a dry hole while well 110/12-6, in which EOG has 100% working interest, was an oil discovery. Engineering studies were initiated with an intent to submit a field development plan to the United Kingdom Department of Energy and Climate Change during the first quarter of 2010. A rig has been contracted and has begun drilling two further exploratory wells offsetting the oil discovery. The first well was declared a dry hole in February 2010 and results for the second well are expected by the end of the first quarter of 2010.

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 additional shallower zones on the acreage purchased. During the second quarter of 2009, EOG completed a monitoring well and in the third quarter of 2009, drilled a horizontal well. The horizontal well is being completed and will be tested during the first quarter of 2010. In addition, to evaluate one of the shallower zones, EOG drilled a second monitoring well during the third quarter of 2009 and is currently drilling a second horizontal well that it plans to complete during the third quarter of 2010.

EOG continues to evaluate other select natural gas and crude oil opportunities outside the United States and Canada primarily by pursuing exploitation opportunities in countries where indigenous natural gas and crude oil 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. At December 31, 2009, EOG's debt-to-total capitalization ratio was 22%. During 2009, EOG funded $3.8 billion in exploration and development and other property, plant and equipment expenditures (excluding asset retirement costs and non-cash acquisition costs), paid $142 million in dividends to common stockholders and purchased $11 million of treasury stock, primarily by utilizing cash provided from its operating activities, proceeds from long-term debt borrowings, proceeds from the sale of its California assets and the issuance of 1.45 million shares of EOG common stock valued at $89.6 million.

Management has not finalized or recommended to EOG's Board a 2010 capital expenditures budget. Management continues to evaluate various factors impacting future natural gas and crude oil prices, including the quantities of natural gas in storage and North American natural gas supplies. In addition, EOG continues to evaluate certain potential exploration and development prospects. All of these factors and uncertainties impact future capital requirements. EOG expects to finalize a 2010 capital expenditures budget early in the second quarter. While EOG currently anticipates an increase in its 2010 capital expenditures budget as compared to its 2009 budget, EOG intends to maintain a strong balance sheet and a below average debt-to-capitalization ratio as compared to its peer group.

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

On 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 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.

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2009 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page F-1.

Net Operating Revenues

During 2009, net operating revenues decreased $2,340 million, or 33%, to $4,787 million from $7,127 million in 2008. Total wellhead revenues, which are revenues generated from sales of EOG's production of natural gas, crude oil and condensate and natural gas liquids, decreased $2,823 million, or 45%, to $3,399 million from $6,222 million in 2008. During 2009, EOG recognized net gains on mark-to-market commodity derivative contracts of $432 million compared to net gains of $598 million in 2008. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party natural gas, crude oil and condensate and natural gas liquids as well as gathering fees associated with gathering third-party natural gas, increased $242 million, or 147%, to $407 million in 2009 from $165 million in 2008. 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. Gains on property dispositions, net in 2008 primarily consist of the gain of $128 million on the sale of Appalachian assets in February 2008.

Wellhead volume and price statistics for the years ended December 31, 2009, 2008 and 2007 were as follows:

Year Ended December 31	**2009**	**2008**	**2007**
Natural Gas Volumes (MMcfd) (1)			
United States	1,134	1,162	971
Canada	224	222	224
Trinidad	273	218	252
Other International (2)	14	17	23
Total	**1,645**	**1,619**	**1,470**
Average Natural Gas Prices ($/Mcf) (3)			
United States	$ 3.72	$ 8.22	$ 6.27
Canada	3.85	7.64	6.25
Trinidad	1.73	3.58	2.71
Other International (2)	4.34	8.18	6.19
Composite	**3.42**	**7.51**	**5.65**
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	47.9	39.5	24.6
Canada	4.1	2.7	2.4
Trinidad	3.1	3.2	4.1
Other International (2)	0.1	0.1	0.1
Total	**55.2**	**45.5**	**31.2**
Average Crude Oil and Condensate Prices ($/Bbl) (3)			
United States	$ 54.42	$ 87.68	$ 68.85
Canada	57.72	89.70	65.27
Trinidad	50.85	92.90	69.84
Other International (2)	53.07	99.30	66.84
Composite	**54.46**	**88.18**	**68.69**
Natural Gas Liquids Volumes (MBbld) (1)			
United States	22.5	15.0	11.1
Canada	1.1	1.0	1.1
Total	**23.6**	**16.0**	**12.2**
Average Natural Gas Liquids Prices ($/Bbl) (3)			
United States	$ 30.03	$ 53.33	$ 47.63
Canada	30.49	54.77	44.54
Composite	**30.05**	**53.42**	**47.36**
Natural Gas Equivalent Volumes (MMcfed) (4)			
United States	1,556	1,490	1,184
Canada	256	244	245
Trinidad	291	237	276
Other International (2)	15	17	24
Total	**2,118**	**1,988**	**1,729**
Total Bcfe (4)	773.0	727.6	631.3

(1) Million cubic feet per day or thousand barrels 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 thousand cubic feet or per barrel, as applicable.
(4) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil and condensate and natural gas liquids. Natural gas equivalents are determined using the ratio of 6.0 thousand cubic feet of natural gas to 1.0 barrel of crude oil and condensate or natural gas liquids.

2009 compared to 2008. 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.

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.

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

Gathering, processing and marketing revenues represent sales of third-party natural gas, crude oil and condensate and natural gas liquids as well as gathering fees associated with gathering third-party natural gas. For the year ended December 31, 2009, substantially all of such revenues were related to sales of third-party natural gas and crude oil. For the years ended December 31, 2008 and 2007, such revenues were primarily related to sales of third-party natural gas. Sales of third-party natural gas are utilized in order to balance firm transportation capacity with production in certain areas. Marketing costs represent the costs of purchasing third-party natural gas and crude oil and the associated transportation costs.

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.

2008 compared to 2007. Wellhead natural gas revenues in 2008 increased $1,419 million, or 47%, to $4,452 million from $3,033 million for 2007 due to a higher composite average wellhead natural gas price ($1,101 million) and increased natural gas deliveries ($318 million). EOG's composite average wellhead natural gas price increased 33% to $7.51 per Mcf in 2008 from $5.65 per Mcf in 2007.

Natural gas deliveries increased 149 MMcfd, or 10%, to 1,619 MMcfd in 2008 from 1,470 MMcfd in 2007. The increase was due to higher production of 191 MMcfd in the United States and initial production of 5 MMcfd in China, partially offset by lower production of 34 MMcfd in Trinidad, 11 MMcfd in the United Kingdom and 2 MMcfd in Canada. The increase in the United States was primarily attributable to increased production from Texas (140 MMcfd), the Rocky Mountain area (54 MMcfd), Mississippi (8 MMcfd) and Kansas (4 MMcfd), partially offset by decreased production due to the February 2008 sale of Appalachian assets (15 MMcfd). The decline in Trinidad was primarily due to decreased deliveries as a result of plant shutdowns due to unplanned maintenance activities (29 MMcfd) and reduced deliveries due to lower demand in 2008 (10 MMcfd), partially offset by increased deliveries to Atlantic LNG Train 4 (ALNG) (5 MMcfd). The decrease in production in the United Kingdom was a result of production declines in both the Arthur and Valkyrie fields.

Wellhead crude oil and condensate revenues increased $680 million, or 87%, to $1,458 million in 2008 from $778 million in 2007, due to an increase of 14.3 MBbld, or 46%, in wellhead crude oil and condensate deliveries ($358 million) and a higher composite average wellhead crude oil and condensate price ($322 million). The increase in deliveries primarily reflects increased production in North Dakota (12 MBbld). The composite average wellhead crude oil and condensate price for 2008 increased 28% to $88.18 per barrel compared to $68.69 per barrel for 2007.

Natural gas liquids revenues increased $102 million, or 49%, to $312 million in 2008 from $210 million in 2007, due to increases in deliveries ($67 million) and a higher composite average price ($35 million). The composite average natural gas liquids price for 2008 increased 13% to $53.42 per barrel compared to $47.36 per barrel for 2007. The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale and Rocky Mountain areas.

During 2008, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $598 million, which included net realized losses of $137 million. During 2007, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $93 million, which included net realized gains of $128 million.

Gathering, processing and marketing revenues less marketing costs increased $5 million to $12 million in 2008 compared to $7 million in 2007. The increase resulted primarily from natural gas marketing operations in the Gulf Coast area.

Operating and Other Expenses

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 thousand cubic feet equivalent (Mcfe) for the years ended December 31, 2009 and 2008:

	2009	2008
Lease and Well	$ 0.75	$ 0.77
Transportation Costs	0.37	0.38
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	1.89	1.74
Other Property, Plant and Equipment	0.12	0.09
General and Administrative (G&A)	0.32	0.34
Net Interest Expense	0.13	0.07
Total (1)	**$ 3.58**	**$ 3.39**

(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 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 natural gas and crude oil 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 costs of operations to restore or maintain production from existing wells.

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

Lease and well expenses of $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 represent costs incurred directly by EOG from third-party carriers 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 third-party costs associated with transporting crude oil.

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 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, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

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

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 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 calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

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 United Kingdom 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 include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are 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 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 the Enron Corp. 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.

2008 compared to 2007. During 2008, operating expenses of $3,360 million were $769 million higher than the $2,591 million incurred in 2007. The following table presents the costs per Mcfe for the years ended December 31, 2008 and 2007:

		2008		2007
Lease and Well	$	0.77	$	0.72
Transportation Costs		0.38		0.24
DD&A -				
Oil and Gas Properties		1.74		1.63
Other Property, Plant and Equipment		0.09		0.06
G&A		0.34		0.33
Net Interest Expense		0.07		0.07
Total (1)	**$**	**3.39**	**$**	**3.05**

(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 2008 compared to 2007 are set forth below.

Lease and well expenses of $559 million in 2008 increased $107 million from $452 million in 2007 due primarily to higher operating and maintenance expenses ($78 million) and higher lease and well administrative expenses ($28 million), both in the United States.

Transportation costs of $274 million in 2008 increased $122 million from $152 million in 2007 primarily due to increased production and costs associated with marketing arrangements to transport production from the Fort Worth Basin Barnett Shale area ($64 million) and the Rocky Mountain area ($38 million) to downstream markets.

DD&A expenses in 2008 increased $261 million to $1,327 million from $1,066 million in 2007. DD&A expenses associated with oil and gas properties were $236 million higher than in 2007 primarily due to higher unit rates described below and as a result of increased production in the United States ($210 million), partially offset by a decrease in production in the United Kingdom ($10 million) and in Trinidad ($3 million). DD&A rates increased due primarily to a proportional increase in production from higher cost properties in the United States ($15 million) and Canada ($8 million). Changes in the Canadian exchange rate ($11 million) also contributed to the DD&A expense increase.

DD&A expenses associated with other property, plant and equipment were $25 million higher in 2008 than in 2007 primarily due to increased expenditures associated with natural gas gathering systems in the Fort Worth Basin Barnett Shale area.

G&A expenses of $244 million in 2008 were $38 million higher than 2007 due primarily to higher employee-related costs ($33 million). The increase in employee-related costs primarily reflects higher stock-based compensation expenses ($18 million).

Net interest expense of $52 million in 2008 increased $5 million from $47 million in 2007 primarily due to a higher average debt balance ($18 million), partially offset by higher capitalized interest ($13 million).

Gathering and processing costs increased $13 million to $41 million in 2008 as compared to $28 million in 2007. The increase primarily reflects increased activities in the Fort Worth Basin Barnett Shale and Rocky Mountain areas.

Exploration costs of $194 million in 2008 increased $44 million from $150 million for the same prior year period primarily due to increased geological and geophysical expenditures in the United States ($27 million) and higher employee-related costs ($15 million). The increase in geological and geophysical expenditures in the United States was primarily attributable to activities in the Fort Worth Basin Barnett Shale area ($21 million).

Impairments of $193 million in 2008 were $45 million higher than impairments of $148 million in 2007 due primarily to increased amortization costs as a result of increased leasehold acquisition expenditures in the United States ($30 million) and Canada ($12 million), an impairment in Trinidad recorded in the second quarter of 2008 as a result of EOG's relinquishment of its rights to LRL ($20 million) and an impairment in the United Kingdom for the Arthur field ($6 million), partially offset by decreased impairments in Canada ($20 million). EOG recorded impairments of proved properties of $86 million and $82 million for 2008 and 2007, respectively.

Taxes other than income in 2008 increased $113 million to $321 million (5.2% of wellhead revenues) from $208 million (5.2% of wellhead revenues) in 2007 primarily due to an increase in severance/production taxes in the United States as a result of increased wellhead revenues ($86 million), a decrease in credits taken in 2008 for Texas high cost gas severance tax rate reductions ($13 million) and increased ad valorem/property taxes as a result of higher property valuations in the United States ($20 million).

Income tax provision of $1,310 million in 2008 increased $769 million compared to 2007 due primarily to increased pretax income. The net effective tax rate for 2008 increased to 35% from 33% in 2007. The increase in the 2008 net effective tax rate is primarily due to a Canadian federal tax rate reduction in 2007.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2009 were funds generated from operations, net proceeds from the issuance 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; repayments of debt; and redemptions of preferred stock.

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 ($11 million) and debt issuance costs ($9 million).

2008 compared to 2007. Net cash provided by operating activities of $4,633 million in 2008 increased $1,732 million from $2,901 million in 2007 primarily reflecting an increase in wellhead revenues ($2,202 million); favorable changes in working capital and other assets and liabilities ($170 million); an increase in gathering, processing and marketing revenues ($91 million); and a decrease in cash paid for income taxes ($50 million); partially offset by an increase in cash operating expenses ($404 million); an increase in marketing costs ($86 million); an unfavorable change in the net cash flow from the settlement of financial commodity derivative contracts ($265 million); and an increase in cash paid for interest expense ($9 million).

Net cash used in investing activities of $4,967 million in 2008 increased by $1,511 million from $3,456 million for the same period of 2007 due primarily to an increase in additions to oil and gas properties ($1,317 million), unfavorable changes in working capital associated with investing activities ($296 million) and an increase in additions to other property, plant and equipment ($199 million), partially offset by an increase in proceeds from sales of assets ($300 million), primarily reflecting net proceeds from the sale of EOG's Appalachian assets.

Net cash provided by financing activities of $645 million in 2008 included the issuance of long-term debt ($750 million), proceeds from stock options exercised and employee stock purchase plan activity ($73 million) and excess tax benefits from stock-based compensation ($6 million). Cash used in financing activities during 2008 included cash dividend payments ($115 million), Trinidad revolving credit facility repayment ($38 million), treasury stock purchases ($18 million), debt issuance costs ($8 million) and the redemption of preferred stock ($5 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2009, 2008 and 2007 (in millions):

	Actual		
	2009	**2008**	**2007**
Expenditure Category			
Capital			
Drilling and Facilities	$ 2,417	$ 3,990	$ 2,976
Leasehold Acquisitions	424	521	278
Property Acquisitions (1)	707	109	20
Capitalized Interest	55	43	29
Subtotal	3,603	4,663	3,303
Exploration Costs	170	194	150
Dry Hole Costs	51	55	115
Exploration and Development Expenditures	3,824	4,912	3,568
Asset Retirement Costs	84	181	31
Total Exploration and Development Expenditures	3,908	5,093	3,599
Other Property, Plant and Equipment	326	477	277
Total Expenditures	**$ 4,234**	**$ 5,570**	**$ 3,876**

(1) In 2009, property acquisitions includes non-cash additions of $353 million related to a property exchange transaction in the Rocky Mountain area and contingent consideration, with a fair value of $35 million, related to the acquisition of the Haynesville Assets.

Exploration and development expenditures of $3,824 million for 2009 were $1,088 million lower than the prior year due primarily to decreased drilling and facilities expenditures in the United States ($1,529 million), Canada ($44 million) and Trinidad ($41 million); decreased leasehold acquisition expenditures in Canada ($122 million); decreased geological and geophysical expenditures in the United States ($23 million); changes in the foreign currency exchange rate in Canada ($16 million); decreased property acquisition expenditures in Trinidad ($15 million), Canada ($14 million) and China ($10 million); and decreased dry hole costs in Canada ($11 million) and the United States ($4 million). These decreases were partially offset by increased property acquisition expenditures in the United States ($638 million), increased drilling and facilities expenditures in China ($41 million) and the United Kingdom ($10 million), increased leasehold acquisition expenditures in the United States ($29 million), increased capitalized interest in the United States ($15 million) and increased dry hole costs in the United Kingdom ($12 million). The 2009 exploration and development expenditures of $3,824 million include $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 include $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 2007 exploration and development expenditures of $3,568 million include $2,681 million in development, $838 million in exploration, $29 million in capitalized interest and $20 million in property acquisitions.

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

Derivative Transactions

During 2009, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $432 million, which included net realized gains of $1,278 million. During 2008, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $598 million, which included net realized losses of $137 million. See Note 11 to Consolidated Financial Statements.

Financial Collar Contracts. The total fair value of EOG's natural gas financial collar contracts at December 31, 2009 was a positive $34 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial collar contracts at February 25, 2010. The notional volumes are expressed in million British thermal units per day (MMBtud) and prices are expressed in dollars per million British thermal units ($/MMBtu). The average floor price of EOG's outstanding natural gas financial collar contracts for 2010 is $9.34 per million British thermal units (MMBtu) and the average ceiling price is $11.54 per MMBtu.

Natural Gas Financial Collar Contracts					
		Floor Price		Ceiling Price	
	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
2010					
January (closed)	40,000	$11.44 - 11.47	$11.45	$13.79 - 13.90	$13.85
February (closed)	40,000	11.38 - 11.41	11.40	13.75 - 13.85	13.80
March (closed)	40,000	11.13 - 11.15	11.14	13.50 - 13.60	13.55
April	40,000	9.40 - 9.45	9.42	11.55 - 11.65	11.60
May	40,000	9.24 - 9.29	9.26	11.41 - 11.55	11.48
June	40,000	9.31 - 9.36	9.34	11.49 - 11.60	11.55

On April 29, 2009, EOG settled its natural gas financial collar contracts with notional volumes of 40,000 MMBtud for the July 1, 2010 to December 31, 2010 period and received proceeds of $26.5 million.

Financial Price Swap Contracts. The total fair value of EOG's natural gas financial price swap contracts at December 31, 2009 was a positive $16 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial price swap contracts at February 25, 2010. The average price of EOG's natural gas financial price swap contracts for 2010 is $9.21 per MMBtu.

Natural Gas Financial Price Swap Contracts		
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2010		
January (closed)	20,000	$11.20
February (closed)	20,000	11.15
March (closed)	20,000	10.89
April	20,000	9.29
May	20,000	9.13
June	20,000	9.21

On April 24, 2009, EOG settled its natural gas financial price swap contracts with notional volumes of 20,000 MMBtud for the July 1, 2010 to December 31, 2010 period and received proceeds of $12.1 million.

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 at December 31, 2009 was a negative $66 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at February 25, 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)
2010		
First Quarter [(1)]	65,000	$(1.72)
Second Quarter	65,000	(2.56)
Third Quarter	65,000	(3.17)
Fourth Quarter	65,000	(3.73)
2011		
First Quarter	65,000	$(1.89)

(1) Includes closed contracts for the month of January and February 2010.

Financing

EOG's debt-to-total capitalization ratio was 22% at December 31, 2009 compared to 17% at December 31, 2008.

During 2009, total debt increased $900 million to $2,797 million. The estimated fair value of EOG's debt at December 31, 2009 and 2008 was $3,056 million and $1,933 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, 2009, a 1% decline in interest rates would result in a $187 million increase in the estimated fair value of the fixed rate obligations. See Note 2 to Consolidated Financial Statements.

During 2009, EOG utilized cash provided by operating activities, proceeds from the offering of its 5.625% Senior Notes due 2019 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 $1.0 billion commercial paper program, the maximum outstanding at any time during 2009 was $675 million, and the amount outstanding at year-end was zero. The maximum amount outstanding under uncommitted credit facilities during 2009 was $17 million with no amounts outstanding at year-end. EOG considers this excess availability, which is backed by the $1.0 billion unsecured Revolving Credit Agreement with domestic and foreign lenders described in Note 2 to Consolidated Financial Statements, to be ample to meet its ongoing operating needs.

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 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.

On September 30, 2008, EOG completed its public offering of $400 million aggregate principal amount of 6.125% Senior Notes due 2013 and $350 million aggregate principal amount of 6.875% Senior Notes due 2018 (Notes). Interest on the Notes is payable semi-annually in arrears on April 1 and October 1 of each year, beginning April 1, 2009. Net proceeds from the offering of approximately $743 million were used for general corporate purposes, including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2009 (in thousands):

Contractual Obligations [1]	Total	2010	2011 - 2012	2013 - 2014	2015 & Beyond
Long-Term Debt	$ 2,797,000	$ 37,000	$ 220,000	$ 550,000	$ 1,990,000
Non-Cancelable Operating Leases	305,068	92,105	64,221	48,479	100,263
Interest Payments on Long-Term Debt	1,313,300	166,693	317,145	273,683	555,779
Pipeline Transportation Service Commitments [2]	2,583,090	247,460	610,542	603,375	1,121,713
Drilling Rig Commitments [3]	181,615	158,302	23,313	-	-
Seismic Purchase Obligations	9,667	9,667	-	-	-
Other Purchase Obligations	79,541	74,851	4,090	600	-
Total Contractual Obligations	**$ 7,269,281**	**$ 786,078**	**$ 1,239,311**	**$ 1,476,137**	**$ 3,767,755**

(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, 2009. 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 2009, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Canada, Trinidad, the United Kingdom and China. The foreign currency most significant to EOG's operations during 2009 was the Canadian dollar. The fluctuation of the Canadian dollar in 2009 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 ASC. Under those provisions, as of December 31, 2009, EOG recorded the fair value of the foreign currency swap of $49 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 $5 million for the year ended December 31, 2009. The change is included in Accumulated Other Comprehensive Income in the Stockholders' Equity section of the Consolidated Balance Sheets.

Outlook

Pricing. Natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of future United States and Canada natural gas and crude oil price trends, and there remains a rather wide divergence in the opinions held by some in the industry. Being primarily a natural gas producer, EOG is more significantly impacted by changes in natural gas prices than by changes in crude oil and condensate or natural gas liquids prices. However, crude oil and condensate and natural gas liquids production comprised a larger portion of EOG's production mix in 2009 than in prior years and is expected to comprise an even larger portion in 2010. Longer term natural gas prices will be determined by the supply of and demand for natural gas as well as the prices of competing fuels, such as crude oil and coal. The market price of natural gas and crude oil and condensate and natural gas liquids in 2010 will impact the amount of cash generated from operating activities, which will in turn impact the level of EOG's 2010 total capital expenditures as well as its production.

Including the impact of EOG's 2010 natural gas hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2010 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $30 million for net income and $45 million for cash flows from operating activities. EOG's price sensitivity in 2010 for each $1.00 per barrel change in wellhead crude oil and condensate price, combined with the related change in natural gas liquids price, is approximately $22 million for net income and $33 million for cash flows from operating activities. For information regarding EOG's natural gas hedge position as of December 31, 2009, 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 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.

Management has not finalized or recommended to EOG's Board a 2010 capital expenditures budget. Management continues to evaluate various factors impacting future natural gas and crude oil prices, including the quantities of natural gas in storage and North American natural gas supplies. In addition, EOG continues to evaluate certain potential exploration and development prospects. All of these factors and uncertainties impact future capital requirements. EOG expects to finalize a 2010 capital expenditures budget early in the second quarter. While EOG currently anticipates an increase in its 2010 capital expenditures budget as compared to its 2009 budget, EOG intends to maintain a strong balance sheet and a below average debt-to-capitalization ratio as compared to its peer group.

Operations. EOG expects to increase overall production in 2010 by 13% over 2009 levels. Total United States production is expected to increase by 15%, comprised of an increase in crude oil and condensate and natural gas liquids production of 53% and 31%, respectively.

Environmental Regulations

Various foreign, 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 natural gas and crude oil 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 United States Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions.

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.

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 and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by certain of the Canadian provinces in which EOG operates. EOG is unable to predict the timing, scope and effect of any such proposed laws, regulations and treaties, 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 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 will continue to review the risks to its business and operations associated with all environmental matters, including climate change. In addition, EOG will continue to monitor and assess any new policies, legislation or regulations in the areas where it operates to determine the impact on its operations and take appropriate actions, where necessary.

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 natural gas, crude oil and condensate and natural gas liquids 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.

Oil and Gas Exploration Costs

EOG accounts for its natural gas and crude oil 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, 2009 and 2008, 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 natural gas and crude oil, 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: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) 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 natural gas and crude oil 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 natural gas, crude oil and related commodities;
- changes in demand for natural gas, crude oil and related commodities, including ammonia and methanol;
- the extent to which EOG is successful in its efforts to discover and market reserves and to acquire natural gas and crude oil properties;
- 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 natural gas and crude oil exploration and development projects, given the risks and uncertainties inherent in drilling, completing and operating natural gas and crude oil wells and the potential for interruptions of production, whether involuntary or intentional as a result of market or other conditions;
- 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;
- changes in government policies, laws and regulations, including environmental and tax laws and regulations;
- 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;
- EOG's ability to obtain access to surface locations for drilling and production facilities;
- the extent to which EOG's third-party-operated natural gas and crude oil properties are operated successfully and economically;
- EOG's ability to effectively integrate acquired natural gas and crude oil 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;
- weather, including its impact on natural gas and crude oil 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 accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- 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 extent and effect of any hedging activities engaged in by EOG;
- 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 19 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.

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, 2009. 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, 2009 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, 2009. 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, 2009. 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 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, 2009 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 2010 Annual Meeting of Stockholders to be filed not later than April 30, 2010 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 and principal financial and 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 and 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 and 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 2010 Annual Meeting of Stockholders to be filed not later than April 30, 2010. 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 2010 Annual Meeting of Stockholders to be filed not later than April 30, 2010.

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. The 2008 Plan provides for grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards, up to an aggregate maximum of 6.0 million shares of common stock, plus shares underlying forfeited or cancelled grants under EOG's 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). The 2008 Plan, the 1992 Stock Plan, the 1993 Nonemployee Directors Stock Option Plan and the Employee Stock Purchase Plan have 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. Restricted shares, 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 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, 2009, 104,883 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, 2009.

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	10,395,723	$68.25	2,260,836 (1)(2)
Equity Compensation Plans Not Approved by EOG Stockholders	1,648,349	$22.40	15,117 (3)
Total	**12,044,072**	**$61.97**	**2,275,953**

(1) Of these securities, 38,602 shares remain available for purchase under the Employee Stock Purchase Plan.

(2) Of these securities, 769,010 could be issued as restricted stock or restricted stock units under the 2008 Plan.

(3) Represents 15,117 shares that remain available for issuance under the Deferral Plan (as described below). See the related discussion below regarding the amendment and continuation of the 1996 Deferral Plan.

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 2010 Annual Meeting of Stockholders to be filed not later than April 30, 2010.

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 2010 Annual Meeting of Stockholders to be filed not later than April 30, 2010.

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-6 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 from time to time 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, 2009. 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, 2009.

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
Chairman of the Board and
Chief Executive Officer

TIMOTHY K. DRIGGERS
Vice President and Chief
Financial Officer

Houston, Texas
February 25, 2010

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, 2009 and 2008, 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, 2009. 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, 2009, 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, and 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 the EOG Resources, Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, present 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, 2009, 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, on December 31, 2009, the Company adopted Accounting Standards Update No. 2010-3, "Oil and Gas Reserve Estimation and Disclosures."

DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2010

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

Year Ended December 31	2009	2008	2007
Net Operating Revenues			
Natural Gas	$ 2,050,963	$ 4,452,058	$ 3,032,805
Crude Oil, Condensate and Natural Gas Liquids	1,348,510	1,769,926	987,523
Gains on Mark-to-Market Commodity Derivative Contracts	431,757	597,911	93,108
Gathering, Processing and Marketing	407,116	164,535	73,539
Gains on Property Dispositions, Net	535,436	123,473	43,628
Other, Net	13,177	19,240	8,700
Total	4,786,959	7,127,143	4,239,303
Operating Expenses			
Lease and Well	579,290	559,185	452,044
Transportation Costs	283,329	274,090	152,236
Gathering and Processing Costs	57,632	40,550	27,775
Exploration Costs	169,592	193,886	150,445
Dry Hole Costs	51,243	55,167	115,382
Impairments	305,832	192,859	147,517
Marketing Costs	397,375	152,842	66,680
Depreciation, Depletion and Amortization	1,549,188	1,326,875	1,065,545
General and Administrative	248,274	243,708	205,210
Taxes Other Than Income	174,363	320,796	208,073
Total	3,816,118	3,359,958	2,590,907
Operating Income	970,841	3,767,185	1,648,396
Other Income, Net	2,071	31,012	29,250
Income Before Interest Expense and Income Taxes	972,912	3,798,197	1,677,646
Interest Expense			
Incurred	155,820	94,286	76,102
Capitalized	(54,919)	(42,628)	(29,324)
Net Interest Expense	100,901	51,658	46,778
Income Before Income Taxes	872,011	3,746,539	1,630,868
Income Tax Provision	325,384	1,309,620	540,950
Net Income	546,627	2,436,919	1,089,918
Preferred Stock Dividends	-	443	6,663
Net Income Available to Common Stockholders	**$ 546,627**	**$ 2,436,476**	**$ 1,083,255**
Net Income Per Share Available to Common Stockholders			
Basic	$ 2.20	$ 9.88	$ 4.45
Diluted	$ 2.17	$ 9.72	$ 4.37
Dividends Declared per Common Share	$ 0.58	$ 0.51	$ 0.36
Average Number of Common Shares			
Basic	248,996	246,662	243,469
Diluted	251,884	250,542	247,637
Comprehensive Income			
Net Income	$ 546,627	$ 2,436,919	$ 1,089,918
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	308,286	(431,940)	282,619
Foreign Currency Swap Transaction	6,336	(9,637)	10,789
Income Tax Related to Foreign Currency Swap Transaction	(1,519)	2,442	(3,086)
Defined Benefit Pension and Postretirement Plans	(1,469)	608	(595)
Income Tax Related to Defined Benefit Pension and Postretirement Plans	299	(388)	271
Comprehensive Income	**$ 858,560**	**$ 1,998,004**	**$ 1,379,916**

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	2009	2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 685,751	$ 331,311
Accounts Receivable, Net	771,417	722,695
Inventories	261,723	187,970
Assets from Price Risk Management Activities	20,915	779,483
Income Taxes Receivable	37,009	27,053
Other	62,726	59,939
Total	1,839,541	2,108,451
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	24,614,311	20,803,629
Other Property, Plant and Equipment	1,350,132	1,057,888
Total Property, Plant and Equipment	25,964,443	21,861,517
Less: Accumulated Depreciation, Depletion and Amortization	(9,825,218)	(8,204,215)
Total Property, Plant and Equipment, Net	16,139,225	13,657,302
Other Assets	139,901	185,473
Total Assets	**$ 18,118,667**	**$ 15,951,226**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 979,139	$ 1,122,209
Accrued Taxes Payable	92,858	86,265
Dividends Payable	36,286	33,461
Liabilities from Price Risk Management Activities	27,218	4,429
Deferred Income Taxes	35,414	368,231
Current Portion of Long-Term Debt	37,000	37,000
Other	137,645	113,321
Total	1,345,560	1,764,916
Long-Term Debt	2,760,000	1,860,000
Other Liabilities	632,652	498,291
Deferred Income Taxes	3,382,413	2,813,522
Commitment and Contingencies (Note 7)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized: 252,627,177 Shares and 249,758,577 Shares Issued at December 31, 2009 and 2008, respectively	202,526	202,498
Additional Paid in Capital	596,702	323,805
Accumulated Other Comprehensive Income	339,720	27,787
Retained Earnings	8,866,747	8,466,143
Common Stock Held in Treasury, 118,525 Shares and 126,911 Shares at December 31, 2009 and 2008, respectively	(7,653)	(5,736)
Total Stockholders' Equity	9,998,042	9,014,497
Total Liabilities and Stockholders' Equity	**$ 18,118,667**	**$ 15,951,226**

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 Stockholders' Equity
Balance at December 31, 2006	$ 52,887	$202,495	$129,986	$176,704	$5,151,034	$(113,435)	$5,599,671
Net Income	-	-	-	-	1,089,918	-	1,089,918
Redemption of Preferred Stock	(48,260)	-	-	-	-	-	(48,260)
Amortization of Preferred Stock Discount	350	-	-	-	(350)	-	-
Preferred Stock Dividends Declared	-	-	-	-	(6,313)	-	(6,313)
Common Stock Dividends Declared, $0.36 Per Share	-	-	-	-	(88,368)	-	(88,368)
Foreign Currency Translation Adjustments	-	-	-	282,619	-	-	282,619
Foreign Currency Swap Transaction, Net of Tax	-	-	-	7,703	-	-	7,703
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	-	(324)	-	-	(324)
Treasury Stock Issued Under Stock Plans	-	-	16,205	-	-	30,106	46,311
Excess Tax Benefits from Stock-Based Compensation	-	-	29,084	-	-	-	29,084
Restricted Stock and Restricted Stock Units	-	-	(21,426)	-	-	21,426	-
Stock-Based Compensation Expenses	-	-	67,253	-	-	-	67,253
Adoption of Accounting Standard for Uncertainty in Income Taxes	-	-	-	-	10,800	-	10,800
Balance at December 31, 2007	4,977	202,495	221,102	466,702	6,156,721	(61,903)	6,990,094
Net Income	-	-	-	-	2,436,919	-	2,436,919
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)	-	(127,054)
Foreign Currency Translation Adjustments	-	-	-	(431,940)	-	-	(431,940)
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	-	-	7,260	-	-	47,649	54,909
Excess Tax Benefits from Stock-Based Compensation	-	-	6,446	-	-	-	6,446
Restricted Stock and Restricted Stock Units	-	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)	9,014,497
Net Income	-	-	-	-	546,627	-	546,627
Common Stock Issued Under Stock Plans	-	3	18,641	-	-	-	18,644
Common Stock Dividends Declared, $0.58 Per Share	-	-	-	-	(146,023)	-	(146,023)
Foreign Currency Translation Adjustments	-	-	-	308,286	-	-	308,286
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	-	-	(4,240)	-	-	(4,923)	(9,163)
Excess Tax Benefits from Stock-Based Compensation	-	-	76,134	-	-	-	76,134
Restricted Stock and Restricted Stock Units	-	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)	$9,998,042

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	2009	2008	2007
Cash Flows From Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	$ 546,627	$ 2,436,919	$ 1,089,918
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	1,549,188	1,326,875	1,065,545
Impairments	305,832	192,859	147,517
Stock-Based Compensation Expenses	95,180	97,493	67,253
Deferred Income Taxes	174,392	1,133,630	426,827
Gains on Property Dispositions, Net	(535,436)	(123,473)	(43,628)
Other, Net	6,761	(14,919)	(510)
Dry Hole Costs	51,243	55,167	115,382
Mark-to-Market Commodity Derivative Contracts			
Total Gains	(431,757)	(597,911)	(93,108)
Realized Gains (Losses)	1,277,584	(136,625)	127,969
Excess Tax Benefits from Stock-Based Compensation	(76,134)	(6,446)	(27,339)
Other, Net	18,862	13,229	24,268
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	(47,818)	95,165	(85,024)
Inventories	(50,146)	(92,049)	9,638
Accounts Payable	(153,565)	30,253	228,354
Accrued Taxes Payable	90,929	72,467	(12,663)
Other Assets	(5,515)	(10,715)	(8,416)
Other Liabilities	(12,305)	9,061	12,614
Changes in Components of Working Capital Associated with Investing and Financing Activities	118,517	152,269	(143,594)
Net Cash Provided by Operating Activities	2,922,439	4,633,249	2,901,003
Investing Cash Flows			
Additions to Oil and Gas Properties	(3,176,783)	(4,718,860)	(3,401,986)
Additions to Other Property, Plant and Equipment	(326,226)	(476,611)	(277,076)
Proceeds from Sales of Assets	212,000	383,559	83,295
Changes in Components of Working Capital Associated with Investing Activities	(118,221)	(152,374)	143,668
Other, Net	(5,321)	(2,232)	(3,675)
Net Cash Used in Investing Activities	(3,414,551)	(4,966,518)	(3,455,774)
Financing Cash Flows			
Long-Term Debt Borrowings	900,000	750,000	610,000
Long-Term Debt Repayments	-	(38,000)	(158,442)
Dividends Paid	(142,260)	(115,204)	(84,020)
Redemption of Preferred Stock	-	(5,395)	(51,197)
Excess Tax Benefits from Stock-Based Compensation	76,134	6,446	27,339
Treasury Stock Purchased	(10,986)	(17,834)	(7,638)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	20,465	72,572	55,320
Debt Issuance Costs	(8,895)	(7,585)	(5,206)
Other, Net	(296)	105	(71)
Net Cash Provided by Financing Activities	834,162	645,105	386,085
Effect of Exchange Rate Changes on Cash	12,390	(34,756)	4,662
Increase (Decrease) in Cash and Cash Equivalents	354,440	277,080	(164,024)
Cash and Cash Equivalents at Beginning of Year	331,311	54,231	218,255
Cash and Cash Equivalents at End of Year	**$ 685,751**	**$ 331,311**	**$ 54,231**

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

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. The carrying values of cash and cash equivalents, marketable securities, commodity derivative contracts, accounts receivable 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 natural gas and crude oil 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 they have 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 in the Gulf of Mexico. 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 natural gas and crude oil, 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). 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 natural gas and crude oil 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.

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

Arrangements for natural gas, crude oil and condensate and natural gas liquids 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 natural gas, crude oil and condensate and natural gas liquids 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, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

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 Price 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, 2009, 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 (Losses) 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 (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. 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. 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 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 United States Securities and Exchange Commission (SEC) final rule, "Modernization of Oil and Gas Reporting," as discussed below. ASU No. 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 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. EOG adopted ASU No. 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.

In June 2009, the FASB issued guidance which establishes the FASB ASC as the source of authoritative accounting principles recognized by the FASB to be applied in the preparation of financial statements in conformity with GAAP. This guidance explicitly recognizes rules and interpretive releases of the SEC under federal securities laws as authoritative GAAP for SEC registrants. The ASC became effective for interim and annual periods ending after September 15, 2009. EOG has modified its disclosures to appropriately update references to GAAP included in this Annual Report on Form 10-K.

Effective April 1, 2009, EOG adopted the provisions of the Subsequent Events Topic of the ASC (ASC Topic 855). ASC Topic 855 clarifies that management must evaluate, as of each reporting period, events or transactions that occur after the balance sheet date and through the date that the financial statements are issued or available to be issued, both for interim and annual reporting periods. The provisions of ASC Topic 855 became effective prospectively for interim and annual reporting periods ending after June 15, 2009. As of February 25, 2010, EOG has determined that there are no subsequent events which require recognition or disclosure in these consolidated financial statements.

Effective January 1, 2009, EOG adopted the provisions of the Business Combinations Topic of the ASC (ASC Topic 805). ASC Topic 805 establishes principles and requirements for how the acquirer recognizes and measures in the financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired, as well as determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. In April 2009, the FASB amended the provisions of ASC Topic 805 related to recognition, measurement and disclosure of assets and liabilities assumed in a business combination that arise from contingencies. The amended provisions of ASC Topic 805 became effective January 1, 2009. See Note 17.

Effective January 1, 2009, EOG adopted the expanded disclosure provisions of ASC Topic 815. The new provisions, which were issued by the FASB in March 2008, do not expand the scope of ASC Topic 815, but require expanded disclosures about an entity's derivative instruments and hedging activities. The expanded disclosure provisions became effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. See Note 13.

The Fair Value Measurements and Disclosures Topic of the ASC (ASC Topic 820) was issued by the FASB in September 2006 and provides a definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. ASC Topic 820 also establishes a fair value hierarchy and requires disclosure of fair value measurements within that hierarchy. In February 2008, the FASB amended ASC Topic 820 to delay the effective date of the measurement and disclosure provisions for all nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008. EOG partially adopted ASC Topic 820 effective January 1, 2008 and adopted the provisions related to nonfinancial assets and liabilities effective January 1, 2009. See Note 12.

2. Long-Term Debt

Long-Term Debt at December 31, 2009 and 2008 consisted of the following (in thousands):

	2009	2008
6.125% Senior Notes due 2013	$ 400,000	$ 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	-
6.65% Senior Notes due 2028	140,000	140,000
Subsidiary Revolving Credit Facility due 2010	37,000	37,000
7.00% Subsidiary Debt due 2011	220,000	220,000
4.75% Subsidiary Debt due 2014	150,000	150,000
	2,797,000	1,897,000
Less: Current Portion of Long-Term Debt	37,000	37,000
Total	**$ 2,760,000**	**$ 1,860,000**

At December 31, 2009, the aggregate annual maturities of long-term debt were \$37 million in 2010, \$220 million in 2011, zero in 2012, \$400 million in 2013 and \$150 million in 2014.

During 2009 and 2008, 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, 2009. The weighted average interest rates for commercial paper and uncommitted credit facility borrowings for 2009 were 0.96% and 1.07%, respectively.

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 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.

On May 11, 2009, EOG Resources Trinidad Limited, a wholly owned foreign subsidiary of EOG, amended its 3-year, \$75 million Revolving Credit Agreement (Credit Agreement) to extend the scheduled maturity date of the remaining outstanding balance of \$37 million from May 12, 2009 to May 12, 2010. Borrowings under the Credit Agreement accrue interest based, at EOG's option, on either the Eurodollar rate or the base rate of the Credit Agreement's administrative agent. The applicable Eurodollar rate at December 31, 2009 was 2.73%. The weighted average Eurodollar rate for the amount outstanding during the year ended December 31, 2009 was 2.79%.

On September 30, 2008, EOG completed its public offering of \$400 million aggregate principal amount of 6.125% Senior Notes due 2013 and \$350 million aggregate principal amount of 6.875% Senior Notes due 2018 (Notes). Interest on the Notes is payable semi-annually in arrears on April 1 and October 1 of each year, beginning April 1, 2009. Net proceeds from the offering of approximately \$743 million were used for general corporate purposes, including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities.

EOG currently has a \$1.0 billion unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders. The Agreement matures on June 28, 2012. At December 31, 2009, there were no borrowings or letters of credit outstanding under the Agreement. Advances under the Agreement accrue interest based, at EOG's option, on either the London InterBank Offering Rate plus an applicable margin (Eurodollar rate) or the base rate of the Agreement's administrative agent. At December 31, 2009, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 0.42% and 3.25%, respectively.

The Agreement and the Credit Agreement each contain certain restrictive covenants applicable to EOG, including a financial covenant with a maximum debt-to-total capitalization ratio of 65%. There are no other financial covenants in EOG's financing agreements. EOG continues to comply with this financial covenant and does not view it as materially restrictive.

The 6.125% Senior Notes due 2013, the 5.875% Senior Notes due 2017, the 6.875% Senior Notes due 2018, the 2019 Notes and the 6.65% Senior Notes due 2028 were issued through public offerings and have effective interest rates of 6.276%, 5.971%, 7.042%, 5.735% and 6.785%, respectively. The 7.00% Subsidiary Debt due 2011 bears interest at a fixed rate of 7.00% and is guaranteed by EOG.

On March 9, 2004, under Rule 144A of the Securities Act of 1933, as amended, EOG Resources Canada Inc., a wholly-owned subsidiary of EOG, issued notes with a total principal amount of \$150 million, an annual interest rate of 4.75% and a maturity date of March 15, 2014. The notes are guaranteed by EOG. In conjunction with the offering, EOG entered into a 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, 2009 and 2008, EOG recorded the fair value of the foreign currency swap of \$49 million and \$26 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 transaction was an increase in Other Comprehensive Income of \$5 million and \$8 million for the years ended December 31, 2009 and 2007, 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, 2009 and 2008, EOG had $2,797 million and $1,897 million, respectively, of debt, which had estimated fair values of approximately $3,056 million and $1,933 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. EOG purchases shares of its common stock from time to time in the open market. 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, 2009, 6,386,200 shares remained available for purchase under this authorization. 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 from $0.06 per share to $0.09 per share on January 31, 2007 effective beginning with the dividend paid on April 30, 2007, to $0.12 per share on February 7, 2008 effective beginning with the dividend paid on April 30, 2008, to $0.135 per share on July 29, 2008 effective beginning with the dividend paid on October 31, 2008 and to $0.145 per share on February 4, 2009 effective beginning with the dividend paid on April 30, 2009. On February 9, 2010, EOG's Board increased the quarterly cash dividend on the common stock from the current $0.145 per share to $0.155 per share effective beginning with the dividend to be paid on April 30, 2010.

The following summarizes EOG's common stock activity for each of the years ended December 31, 2007, 2008 and 2009 (in thousands):

	Common Shares		
	Issued	**Treasury**	**Outstanding**
Balance at December 31, 2006	249,460	(5,725)	243,735
Treasury Stock Purchased (1)	-	(126)	(126)
Treasury Stock Issued Under Employee Stock Purchase Plan	-	102	102
Treasury Stock Issued Under Other Equity Compensation Plans	-	2,814	2,814
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

(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.

Common Stock Rights Agreement. In February 2000, the Board declared a dividend of one preferred share purchase right (a Right, and the agreement governing the terms of such Rights, as amended, the Rights Agreement) for each outstanding share of EOG common stock. In accordance with the Rights Agreement, each share of common stock issued thereafter by EOG also had one Right associated with it, including each share issued in connection with the two-for-one stock split effected in March 2005. The Rights and the Rights Agreement expired on February 24, 2010.

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) with the rights and preferences. 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, 2009, there were no shares of the Series E outstanding.

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 2009 included equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants ($4 million), net foreign currency transaction gains ($4 million) and losses on sales of warehouse stock ($4 million). Other income, net for 2008 included interest income ($9 million), equity income from investments in CNCL and N2000 ammonia plants ($19 million), net foreign currency transaction losses ($5 million) and settlements received related to the Enron Corp. bankruptcy ($3 million).

5. Income Taxes

The principal components of EOG's net deferred income tax liabilities at December 31, 2009 and 2008 were as follows (in thousands):

	2009	2008
Current Deferred Income Tax (Assets) Liabilities		
Commodity Hedging Contracts	$ 11,559	$ 276,438
Deferred Compensation Plans	(11,121)	(8,226)
Timing Differences Associated With Different Year-ends in Foreign Jurisdictions	27,659	98,736
Other	7,317	1,283
Total Net Current Deferred Income Tax Liabilities	**$ 35,414**	**$ 368,231**
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$ 3,746,302	$ 3,048,651
Non-Producing Leasehold Costs	(67,347)	(50,841)
Seismic Costs Capitalized for Tax	(64,917)	(47,325)
Equity Awards	(76,978)	(52,300)
Capitalized Interest	76,852	62,488
Alternative Minimum Tax Credit Carryforward	(200,034)	(143,142)
Other	(31,465)	(4,009)
Total Net Noncurrent Deferred Income Tax Liabilities	**$ 3,382,413**	**$ 2,813,522**
Total Net Deferred Income Tax Liabilities	**$ 3,417,827**	**$ 3,181,753**

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

	2009	2008	2007
United States	$ 784,248	$ 3,138,175	$ 1,191,093
Foreign	87,763	608,364	439,775
Total	**$ 872,011**	**$ 3,746,539**	**$ 1,630,868**

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

	2009	2008	2007
Current:			
Federal	$ 95,194	$ 50,776	$ (7,284)
State	8,783	5,674	(3,999)
Foreign	47,015	119,540	125,406
Total	150,992	175,990	114,123
Deferred:			
Federal	166,045	1,010,535	416,925
State	31,580	56,540	26,506
Foreign	(23,233)	66,555	(16,604)
Total	174,392	1,133,630	426,827
Income Tax Provision	**$ 325,384**	**$ 1,309,620**	**$ 540,950**

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

	2009	2008	2007
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	3.00	1.08	0.90
Income Tax Provision Related to Foreign Operations	(0.80)	(0.72)	(0.67)
Change in Canadian Federal and Provincial Statutory Tax Rates and Other Canadian Adjustments	-	-	(2.10)
Domestic Production Activities Deduction	0.06	0.01	0.11
Other	0.05	(0.41)	(0.07)
Effective Income Tax Rate	37.31%	34.96%	33.17%

The balance of unrecognized tax benefits at December 31, 2009 was $29 million ($16 million related to 2009), 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, 2005, 2008, 2002 and 2008, respectively.

EOG's foreign subsidiaries' undistributed earnings of approximately $3.0 billion at December 31, 2009 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. Determination of any potential amount of unrecognized deferred income tax liabilities is not practicable.

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. In 2008, EOG generated a regular tax net operating loss of $184 million, which was expected to be carried forward and applied against regular taxable income in future periods. In November 2009, the Worker, Homeownership, and Business Assistance Act of 2009 was enacted, thereby allowing the 2008 net operating loss to be fully utilized as a carryback rather than as a carryforward and as such provided an immediate reduction in income taxes, via a refund, resulting in a benefit of $66 million being reflected in APIC.

In 2009, EOG paid alternative minimum tax (AMT) of $21 million. The AMT paid in 2009, along with AMT of $179 million paid in prior years (cumulative total of $200 million), will be carried forward as a credit available to offset regular income taxes in future periods.

6. Employee Benefit Plans

Pension Plans and Postretirement Benefits

At December 31, 2009, 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 2009, approximately $0.1 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 $22 million, $20 million and $16 million for 2009, 2008 and 2007, 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 $2.3 million, $2.7 million and $2.7 million for 2009, 2008 and 2007, respectively.

For the Canadian and Trinidadian defined benefit pension plans, the benefit obligation, fair value of plan assets and prepaid/(accrued) benefit cost totaled $9.1 million, $7.7 million and $(0.9) million, respectively, at December 31, 2009 and $6.2 million, $6.2 million and $0.3 million, respectively, at December 31, 2008. 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 7.87%, 7.99%, 5.73% and 1.51%, respectively, at December 31, 2009; 7.90%, 8.05%, 5.80% and 1.46%, respectively, at December 31, 2008 and 6.85%, 7.47%, 5.15% and 1.90%, respectively, at December 31, 2007. Weighted average discount rate, rate of compensation increase and rate of pension increase assumptions used to determine benefit obligations for the pension plans were 5.76%, 4.14% and 1.74%, respectively, for the year ended December 31, 2009 and 7.59%, 5.02% and 1.99%, respectively, for the year ended December 31, 2008. The weighted average asset allocation at December 31, 2009 consisted of equities (46%), debt and fixed income securities (44%) and other assets (10%). The weighted average asset allocation at December 31, 2008 consisted of equities (48%), debt and fixed income securities (44%) and other assets (8%).

The fair value of Canada's pension plan assets was $5.0 million at December 31, 2009. Such assets consisted of mutual funds valued using Level 1 inputs, which represent quoted market prices in active markets. The fair value of Trinidad's pension plan assets was $2.7 million at December 31, 2009. Such assets consisted of cash in other currencies ($0.5 million), cash in United States dollars ($0.1 million) and foreign equities ($0.1 million) valued using Level 1 inputs, as well as bonds ($1.6 million), local equities ($0.3 million) and regional equities ($0.1 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 in Trinidad 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 in Canada 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 2009, 2008 and 2007.

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 totaled $5.2 million and $5.1 million, respectively, at December 31, 2009 and each totaled $4.4 million at December 31, 2008. Weighted average discount rate assumptions used to determine benefit obligations for the postretirement plans at December 31, 2009 and 2008 were 5.83% and 6.25%, respectively. Weighted average discount rate assumptions used to determine net periodic benefit cost for the years ended December 31, 2009, 2008 and 2007 were 6.28%, 6.33% and 5.96%, respectively. Net periodic benefit cost recognized for the postretirement benefit plans totaled $0.8 million, $0.8 million and $0.7 million for the years ended December 31, 2009, 2008 and 2007.

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
2010	$ 242	$ 198
2011	294	237
2012	260	267
2013	287	325
2014	458	390
2015 - 2019	2,655	2,880

Postretirement health care trend rates had minimal effect on the amounts reported for the postretirement health care plans for both 2009 and 2008. Most future increases or decreases in healthcare costs would be borne by the employee.

Stock-Based Compensation

During 2009, 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, 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, 2009, 2008 and 2007 was as follows (in millions):

	2009	2008	2007
Lease and Well	$ 23	$ 20	$ 14
Exploration Costs	21	18	13
General and Administrative	51	59	40
Total	$ 95	$ 97	$ 67

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. The 2008 Plan provides for grants of stock options, SARs, restricted stock, restricted stock units and other stock-based awards, up to an aggregate maximum of 6.0 million shares of common stock, plus shares underlying forfeited or cancelled grants under the prior stock plans. Under the 2008 Plan, grants may be made to employees and non-employee members of EOG's Board. At December 31, 2009, approximately 2.2 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 2009, 2008 and 2007, EOG issued treasury shares in connection with stock option 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 benefits of $76 million, $6 million and $29 million for 2009, 2008 and 2007, 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 $38.0 million, $38.9 million and $36.7 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2009, 2008 and 2007 were as follows:

	Stock Options/SARs			ESPP		
	2009	2008	2007	2009	2008	2007
Weighted Average Fair Value of Grants	$30.13	$32.19	$24.23	$25.78	$29.68	$16.11
Expected Volatility	41.90%	38.55%	30.68%	78.89%	37.58%	29.76%
Risk-Free Interest Rate	1.42%	2.53%	4.48%	0.25%	2.64%	5.01%
Dividend Yield	0.70%	0.60%	0.30%	1.00%	0.50%	0.30%
Expected Life	5.5 yrs	5.3 yrs	5.2 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, 2009, 2008 and 2007 (stock options and SARs in thousands):

	2009		2008		2007	
	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	7,802	$52.56	9,373	$41.04	10,150	$35.29
Granted	1,270	80.95	1,231	90.57	1,210	73.46
Exercised [(1)]	(636)	46.56	(2,628)	28.19	(1,820)	29.12
Forfeited	(101)	74.07	(174)	69.22	(167)	56.39
Outstanding at December 31	8,335	57.08	7,802	52.56	9,373	41.04
Stock Options/SARs Exercisable at December 31	5,394	44.45	4,711	37.23	5,617	27.21
Available for Future Grant	2,222		4,555		1,140	

(1) The total intrinsic value of stock options/SARs exercised during the years 2009, 2008 and 2007 was $21.4 million, $217.9 million and $86.4 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, 2009, there were 8,099,972 stock options/SARs vested or expected to vest with a weighted average grant price of $56.40, an intrinsic value of $333 million and a weighted average remaining contractual life of 4.1 years.

The following table summarizes certain information for the stock options and SARs outstanding at December 31, 2009 (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 $ 16.99	476	1	$16.60		476	1	$16.60	
17.00 to 19.99	1,425	3	18.37		1,425	3	18.37	
20.00 to 48.99	683	3	23.42		681	3	23.36	
49.00 to 69.99	2,310	3	61.94		1,933	3	61.99	
70.00 to 136.99	3,441	6	82.13		879	5	79.61	
	8,335	4	57.08	$336,606	5,394	3	44.45	$285,524

(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, 2009, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $77.9 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.7 years.

EOG suspended the ESPP, effective for the July 1, 2009 to December 31, 2009 offering period, due to an insufficient number of shares remaining available under the ESPP. Subject to stockholder approval of an amendment to the ESPP to increase the shares available under the ESPP at the 2010 Annual Meeting of Stockholders, EOG expects to resume the ESPP for the January 1, 2010 to June 30, 2010 offering period. The ESPP was originally approved by EOG's stockholders in 2001 and has a term expiring on July 1, 2011; the amendment to be presented to EOG's stockholders at the 2010 Annual Meeting of Stockholders will, if approved, also extend the term of the ESPP to July 1, 2021. The following table summarizes ESPP activities for the years ended December 31, 2009, 2008 and 2007 (in thousands, except number of participants):

	2009	2008	2007
Approximate Number of Participants	1,128	1,075	860
Shares Purchased	72	103	102
Aggregate Purchase Price	$ 4,150	$ 6,724	$ 5,840

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. Restricted stock units are converted into common shares upon vesting and released to the employee. Stock-based compensation expense related to restricted stock and restricted stock units totaled $57.2 million, $58.6 million and $30.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2009, 2008 and 2007 (shares and units in thousands):

	2009		2008		2007	
	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	3,048	$70.24	3,000	$50.61	2,301	$36.13
Granted	1,197	63.13	795	106.67	1,141	71.28
Released[1]	(553)	31.35	(623)	22.77	(346)	21.20
Forfeited	(56)	78.18	(124)	67.42	(96)	54.58
Outstanding at December 31[2]	3,636	73.69	3,048	70.24	3,000	50.61

(1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2009, 2008 and 2007 was $36.9 million, $55.7 million and $23.8 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, 2009 and 2008 was approximately $353.8 million and $203.0 million, respectively.

At December 31, 2009, unrecognized compensation expense related to restricted stock and restricted stock units totaled $137.4 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 3.0 years.

7. Commitments and Contingencies

Letters of Credit. 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. At December 31, 2008, EOG had standby letters of credit and guarantees outstanding totaling approximately $568 million, of which $445 million represents guarantees of subsidiary indebtedness and $123 million primarily represents guarantees of payment obligations on behalf of subsidiaries. As of February 24, 2010, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2009, 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, 2009, are as follows (in thousands):

	Total Minimum Commitments
2010	$ 582,385
2011 - 2012	702,166
2013 - 2014	652,454
2015 and beyond	1,221,976
	$ 3,158,981

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2022. Rental expenses associated with existing leases amounted to $77 million, $70 million and $60 million for 2009, 2008 and 2007, 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, 2009, 2008 and 2007 (in thousands, except per share data):

	2009	2008	2007
Numerator for Basic and Diluted Earnings per Share -			
Net Income	$ 546,627	$ 2,436,919	$ 1,089,918
Less: Preferred Stock Dividends	-	443	6,663
Net Income Available to Common Stockholders	$ 546,627	$ 2,436,476	$ 1,083,255
Denominator for Basic Earnings per Share -			
Weighted Average Shares	248,996	246,662	243,469
Potential Dilutive Common Shares -			
Stock Options/SARs	1,691	2,629	2,915
Restricted Stock and Restricted Stock Units	1,197	1,251	1,253
Denominator for Diluted Earnings per Share -			
Adjusted Diluted Weighted Average Shares	251,884	250,542	247,637
Net Income Per Share Available to Common Stockholders			
Basic	$ 2.20	$ 9.88	$ 4.45
Diluted	$ 2.17	$ 9.72	$ 4.37

The diluted earnings per share calculation excludes stock options and SARs that were anti-dilutive. The excluded stock options and SARs totaled 2.5 million, 0.1 million and 2.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

9. Supplemental Cash Flow Information

Cash paid for interest and income taxes, net of refunds received, was as follows for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	2009	2008	2007
Interest	$ 100,939	$ 48,029	$ 38,616
Income Taxes, Net of Refunds Received	$ 51,684	$ 94,598	$ 144,234

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 natural gas and crude oil 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, 2009, 2008 and 2007 (in thousands):

	United States	Canada	Trinidad	Other International (1)	Total
2009					
Natural Gas	$ 1,540,042	$ 315,792	$ 172,560	$ 22,569	$ 2,050,963
Crude Oil, Condensate and Natural Gas Liquids	1,192,045	98,118	57,089	1,258	1,348,510
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 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
2008					
Natural Gas	$ 3,497,620	$ 619,792	$ 285,184	$ 49,462	$ 4,452,058
Crude Oil, Condensate and Natural Gas Liquids	1,552,163	107,915	107,878	1,970	1,769,926
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

	United States	Canada	Trinidad	Other International (1)	Total
2007					
Natural Gas	$ 2,220,892	$ 510,473	$ 248,553	$ 52,887	$ 3,032,805
Crude Oil, Condensate and Natural Gas Liquids	806,037	74,841	104,324	2,321	987,523
Gains on Mark-to-Market Commodity Derivative Contracts	93,108	-	-	-	93,108
Gathering, Processing and Marketing	73,539	-	-	-	73,539
Gains (Losses) on Property Dispositions, Net	43,714	55	(116)	(25)	43,628
Other, Net	8,796	(105)	(17)	26	8,700
Net Operating Revenues (2)	3,246,086	585,264	352,744	55,209	4,239,303
Depreciation, Depletion and Amortization	848,051	170,666	24,883	21,945	1,065,545
Operating Income	1,199,816	197,207	247,638	3,735	1,648,396
Interest Income	850	2,474	5,226	1,143	9,693
Other Income (Expense)	7,384	(4,348)	16,609	(88)	19,557
Net Interest Expense	20,262	20,391	6,148	(23)	46,778
Income Before Income Taxes	1,187,788	174,942	263,325	4,813	1,630,868
Income Tax Provision (Benefit)	427,531	(6,728)	116,684	3,463	540,950
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	2,810,265	355,474	109,273	11,592	3,286,604
Total Property, Plant and Equipment, Net	7,364,648	2,543,781	472,096	48,729	10,429,254
Total Assets	8,687,320	2,649,925	692,353	59,309	12,088,907

(1) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(2) EOG had no purchasers in 2009, 2008 or 2007 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 natural gas and crude oil. 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 2009, 2008 and 2007, 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 2009, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $432 million, which included net realized gains of $1,278 million. During 2008, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $598 million, which included net realized losses of $137 million. During 2007, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $93 million, which included net realized gains of $128 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). At December 31, 2008, 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 ($779 million), Other Assets ($57 million), Current Liabilities - Liabilities from Price Risk Management Activities ($4 million) and Other Liabilities ($8 million).

Financial Collar Contracts. Presented below is a comprehensive summary of EOG's natural gas financial collar contracts at December 31, 2009. The notional volumes are expressed in million British thermal units per day (MMBtud) and prices are expressed in dollars per million British thermal units ($/MMBtu). The average floor price of EOG's outstanding natural gas financial collar contracts for 2010 is $10.10 per million British thermal units (MMBtu) and the average ceiling price is $12.38 per MMBtu.

Natural Gas Financial Collar Contracts					
		Floor Price		Ceiling Price	
	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
2010					
January (closed)	40,000	$11.44 - 11.47	$11.45	$13.79 - 13.90	$13.85
February	40,000	11.38 - 11.41	11.40	13.75 - 13.85	13.80
March	40,000	11.13 - 11.15	11.14	13.50 - 13.60	13.55
April	40,000	9.40 - 9.45	9.42	11.55 - 11.65	11.60
May	40,000	9.24 - 9.29	9.26	11.41 - 11.55	11.48
June	40,000	9.31 - 9.36	9.34	11.49 - 11.60	11.55

On April 29, 2009, EOG settled its natural gas financial collar contracts with notional volumes of 40,000 MMBtud for the July 1, 2010 to December 31, 2010 period and received proceeds of $26.5 million.

Financial Price Swap Contracts. Presented below is a comprehensive summary of EOG's natural gas financial price swap contracts at December 31, 2009. The average price of EOG's outstanding natural gas financial price swap contracts for 2010 is $9.92 per MMBtu.

Natural Gas Financial Price Swap Contracts		
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2010		
January (closed)	20,000	$11.20
February	20,000	11.15
March	20,000	10.89
April	20,000	9.29
May	20,000	9.13
June	20,000	9.21

On April 24, 2009, EOG settled its natural gas financial price swap contracts with notional volumes of 20,000 MMBtud for the July 1, 2010 to December 31, 2010 period and received proceeds of $12.1 million.

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, 2009. 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)
2010		
First Quarter [1]	65,000	$(1.72)
Second Quarter	65,000	(2.56)
Third Quarter	65,000	(3.17)
Fourth Quarter	65,000	(3.73)
2011		
First Quarter	65,000	$(1.89)

(1) Includes closed contracts for the month of January 2010.

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.

The following table sets forth the amounts, on a gross basis, and classification of EOG's outstanding derivative financial instruments at December 31, 2009 and December 31, 2008. 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 master netting arrangements (in millions):

Description	Location on Balance Sheet	Fair Value at December 31, 2009	Fair Value at December 31, 2008
Asset Derivatives			
Natural gas collars and price swaps -			
Current portion	Assets from Price Risk Management Activities	$ 50	$ 786
Noncurrent portion	Other Assets	$ -	$ 63
Liability Derivatives			
Natural gas basis swaps -			
Current portion	Liabilities from Price Risk Management Activities	$ 57	$ 11
Noncurrent portion	Other Liabilities	$ 9	$ 14
Foreign currency rate swap -			
Noncurrent portion	Other Liabilities	$ 49	$ 26

Credit Risk. Notional contract amounts are used to express the magnitude of commodity price and foreign currency 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, 2009, EOG's net accounts receivable balance related to United States, Canada, and United Kingdom hydrocarbon sales included one receivable balance which constituted 12% of the total balance. These receivables were due from a crude oil marketing company. The related amounts were collected during early 2010. At December 31, 2008, no individual purchaser's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales accounted for 10% or more of the total balance. In 2009 and 2008, 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, 2009 and 2008. EOG had zero collateral posted at both December 31, 2009 and 2008.

At December 31, 2009 and 2008, EOG had an allowance for doubtful accounts of $13 million for both years of which $11 million for both years were associated with the Enron Corp. bankruptcies in December 2001.

Substantially all of EOG's accounts receivable at December 31, 2009 and 2008 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, 2009, 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 accompanying 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 hierarchy for certain of EOG's financial assets and liabilities carried at fair value at December 31, 2009 and 2008 (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, 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
At December 31, 2008				
Financial Assets:				
Natural gas collars, price swaps and basis swaps	$ -	$ 836	$ -	$ 836
Financial Liabilities:				
Natural gas collars, price swaps and basis swaps	$ -	$ 12	$ -	$ 12
Foreign currency rate swap	-	26	-	26

The estimated fair value of natural gas collar, price swap and basis swap contracts was based upon forward commodity price 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, EOG could be required to make an additional one-time payment to the sellers contingent upon future natural gas prices over a five year period (see Note 17). EOG recorded the fair value of the contingent consideration 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.

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 oil and gas properties. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 14.

Proved oil and gas properties with a carrying amount of $307 million were written down to their fair value of $213 million, resulting in a pretax impairment charge of $94 million for the year ended December 31, 2009. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future natural gas and crude oil prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. See Note 13.

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 2009, 2008 and 2007, 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 $90 million, $58 million and $60 million in the United States operating segment during 2009, 2008 and 2007, respectively, and $4 million, $2 million and $22 million in the Canada operating segment during 2009, 2008 and 2007, respectively. 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. Amortization of unproved oil and gas property costs, including amortization of capitalized interest, was $212 million, $107 million and $66 million for 2009, 2008 and 2007, 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, 2009 and 2008 (in thousands):

		2009		2008
Carrying Amount at Beginning of Period	$	368,159	$	211,124
Liabilities Incurred		70,932		58,942
Liabilities Settled		(29,920)		(18,813)
Accretion		24,218		15,356
Revisions [1]		10,564		111,112
Foreign Currency Translations		12,531		(9,562)
Carrying Amount at End of Period	$	456,484	$	368,159
Current Portion	$	29,630	$	19,459
Noncurrent Portion	$	426,854	$	348,700

(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, 2009, EOG's equity interests in CNCL and N2000 were 12% and 10%, respectively.

At December 31, 2009, the investment in CNCL was $22 million. CNCL commenced ammonia production in June 2002. At December 31, 2009, CNCL had a long-term debt balance of $59 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 borrowings under this agreement. 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 2009, EOG recognized equity income of $0.5 million and received cash dividends of $3 million from CNCL.

At December 31, 2009, the investment in N2000 was $19 million. N2000 commenced ammonia production in August 2004. At December 31, 2009, N2000 had a long-term debt balance of $74 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 borrowings under this agreement. 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 2009, EOG recognized equity income of $3 million and received cash dividends of $4 million from N2000.

16. Suspended Well Costs

EOG's net changes in suspended well costs for the years ended December 31, 2009, 2008 and 2007 are presented below (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Balance at January 1	$ 85,255	$ 148,881	$ 77,365
Additions Pending the Determination of Proved Reserves	75,362	96,698	132,993
Reclassifications to Proved Properties	(40,614)	(120,110)	(23,716)
Charged to Dry Hole Costs	(11,223)	(22,116)	(18,232)
Foreign Currency Translations	9,679	(18,098)	6,105
Other	-	-	(25,634) (1)
Balance at December 31	$ 118,459	$ 85,255	$ 148,881

(1) During 2007, EOG decided to no longer participate in the further evaluation of the Northwest Territories discovery and sold all of its interest to the outside operator for $5 million. Prior to the sale, EOG recorded an impairment charge of approximately $21 million.

The following table provides an aging of suspended well costs at December 31, 2009, 2008 and 2007 (in thousands, except well count):

	Year Ended December 31,		
	2009	2008	2007
Capitalized exploratory well costs that have been capitalized for a period less than one year	$ 51,141	$ 31,784	$ 97,624
Capitalized exploratory well costs that have been capitalized for a period greater than one year	67,318 (1)	53,471 (2)	51,257 (3)
Total	$ 118,459	$ 85,255	$ 148,881
Number of exploratory wells that have been capitalized for a period greater than one year	4	3	2

(1) Consists of costs related to three shale projects in British Columbia, Canada (B.C.) ($45 million) and an outside operated, offshore Central North Sea project in the United Kingdom (U.K.) ($22 million). In the B.C. shale projects, EOG is currently evaluating infrastructure alternatives for delivery of product. In the Central North Sea project, EOG is currently evaluating an export route for production from the project. The operator expects to submit a revised field development plan to the U.K. Department of Energy and Climate Change during the second quarter of 2010 and anticipates approval in late 2010.

(2) Costs related to two shale projects in British Columbia, Canada (B.C.) ($35 million) and an outside operated, offshore Central North Sea project in the United Kingdom ($19 million).

(3) Costs related to a shale project in B.C. ($38 million) and an outside operated, offshore Central North Sea project in the United Kingdom ($13 million).

17. Property Acquisitions and Divestitures

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 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 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. The fair value of such contingent consideration was $35 million at December 31, 2009 (see Note 12). The aggregate consideration recorded in 2009 for the acquisition of the Haynesville Assets was $134 million, including the contingent consideration.

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.

In February 2008, EOG completed a sale of the majority of its producing shallow gas assets and surrounding acreage in the Appalachian Basin to a subsidiary of EXCO Resources, Inc., an independent oil and gas company. The Appalachian area divested included approximately 2,400 operated wells that accounted for approximately 1% of EOG's total 2007 production and approximately 2% of its total year-end 2007 proved reserves. Proceeds on the sale totaled $386 million and EOG realized a pretax gain of $128 million on the sale.

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 amends 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" natural gas and liquids 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. Although every 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 natural gas and liquids 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.

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 engineers and geoscientists performed 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 a reservoir that can be judged, with reasonable certainty, to be continuous and contain economically producible oil and gas, studies were conducted employing numerous data elements and analysis techniques. Such data elements and analysis techniques included, but were not limited to, a combination of seismic data and interpretation, as well as comprehensive sets of wireline logs and/or core data and transient analysis techniques applied to pressure and production data from existing producing wells. EOG has found that studies conducted using the previously mentioned combination of data elements and analysis techniques have been proven effective based on application in analogous reservoirs.

EOG has formulated development plans for all proved undeveloped locations. In these plans, substantially all of the proved undeveloped 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.

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, 2009, 2008 and 2007 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 24 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 natural gas, natural gas liquids and crude oil 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, the Executive Vice President, Exploration and the Vice President and Chief Financial Officer for approval.

Opinions by D&M for the years ended December 31, 2009, 2008 and 2007 covered producing areas containing 81%, 79% and 79%, respectively, of proved reserves of EOG on a net-equivalent-cubic-feet-of-gas 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-cubic-feet-of-gas 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 4, 2010, 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, 2009 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

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, 2009, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2009, 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					
Natural Gas (Bcf) [2]					
Net proved reserves at December 31, 2006	3,470.9	1,309.6	1,295.4	19.0	6,094.9
Revisions of previous estimates	(63.2)	(64.3)	(16.9)	2.5	(141.9)
Purchases in place	1.2	1.2	29.6	-	32.0
Extensions, discoveries and other additions	1,177.5	54.9	-	-	1,232.4
Sales in place	(5.7)	-	-	-	(5.7)
Production	(360.6)	(81.6)	(91.8)	(8.6)	(542.6)
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**

	United States	Canada	Trinidad	Other International [1]	Total
Liquids (MBbl) [3]					
Net proved reserves at December 31, 2006	96,616	9,580	11,504	62	117,762
Revisions of previous estimates	27,933	1,169	(1,179)	20	27,943
Purchases in place	37	-	69	-	106
Extensions, discoveries and other additions	49,418	886	-	-	50,304
Sales in place	(940)	-	-	-	(940)
Production	(13,043)	(1,269)	(1,494)	(35)	(15,841)
Net proved reserves at December 31, 2007	160,021	10,366	8,900	47	179,334
Revisions of previous estimates	(1,592)	854	403	(20)	(355)
Purchases in place	6	-	184	58	248
Extensions, discoveries and other additions	67,877	919	-	-	68,796
Sales in place	(495)	-	-	-	(495)
Production	(19,971)	(1,344)	(1,161)	(20)	(22,496)
Net proved reserves at December 31, 2008	205,846	10,795	8,326	65	225,032
Revisions of previous estimates	10,511	(1,109)	(1,760)	17	7,659
Purchases in place	21,467	-	-	-	21,467
Extensions, discoveries and other additions	76,804	19,807	-	-	96,611
Sales in place	(8,973)	(50)	-	-	(9,023)
Production	(25,714)	(1,885)	(1,123)	(24)	(28,746)
Net proved reserves at December 31, 2009	**279,941**	**27,558**	**5,443**	**58**	**313,000**
Liquids - 2009					
Crude Oil (MBbl) [3]					
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**
Natural Gas Liquids (MBbl) [3]					
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**

	United States	Canada	Trinidad	Other International [1]	Total
Bcf Equivalent (Bcfe) [2]					
Net proved reserves at December 31, 2006	4,050.6	1,367.1	1,364.4	19.4	6,801.5
Revisions of previous estimates	104.4	(57.3)	(23.9)	2.6	25.8
Purchases in place	1.5	1.2	30.0	-	32.7
Extensions, discoveries and other additions	1,474.0	60.2	-	-	1,534.2
Sales in place	(11.4)	-	-	-	(11.4)
Production	(438.9)	(89.2)	(100.8)	(8.8)	(637.7)
Net proved reserves at December 31, 2007	5,180.2	1,282.0	1,269.7	13.2	7,745.1
Revisions of previous estimates	(119.9)	28.1	64.7	(4.3)	(31.4)
Purchases in place	31.1	15.0	1.1	12.5	59.7
Extensions, discoveries and other additions	1,791.6	66.1	-	-	1,857.7
Sales in place	(203.2)	-	-	-	(203.2)
Production	(555.8)	(89.2)	(87.4)	(6.1)	(738.5)
Net proved reserves at December 31, 2008	6,124.0	1,302.0	1,248.1	15.3	8,689.4
Revisions of previous estimates	(314.9)	(453.8)	(115.5)	3.1	(881.1)
Purchases in place	579.6	-	-	-	579.6
Extensions, discoveries and other additions	2,385.8	965.3	-	-	3,351.1
Sales in place	(168.2)	(5.4)	-	-	(173.6)
Production	(576.6)	(93.2)	(114.1)	(5.4)	(789.3)
Net proved reserves at December 31, 2009	**8,029.7**	**1,714.9**	**1,018.5**	**13.0**	**10,776.1**

EOG's revisions of previous estimates for 2009 of negative 881.1 Bcfe included negative revisions of approximately 786.0 Bcfe 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 the 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.

	United States	Canada	Trinidad	Other International (1)	Total
NET PROVED DEVELOPED RESERVES					
Natural Gas (Bcf) (2)					
December 31, 2006	2,416.2	1,162.2	610.0	19.0	4,207.4
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
Liquids (MBbl) (3)					
December 31, 2006	79,555	9,427	6,119	62.0	95,163
December 31, 2007	119,949	10,193	7,222	47.0	137,411
December 31, 2008	159,607	10,416	6,756	65.0	176,844
December 31, 2009	189,322	10,831	3,966	58.0	204,177
Bcf Equivalents (Bcfe) (2)					
December 31, 2006	2,893.5	1,218.8	646.7	19.4	4,778.4
December 31, 2007	3,861.5	1,140.3	960.0	13.2	5,975.0
December 31, 2008	4,502.3	1,166.2	929.6	15.3	6,613.4
December 31, 2009	4,466.0	745.9	633.3	13.0	5,858.2
NET PROVED UNDEVELOPED RESERVES					
Natural Gas (Bcf) (2)					
December 31, 2006	1,054.8	147.4	685.3	-	1,887.5
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
Liquids (MBbl) (3)					
December 31, 2006	17,060	154	5,385	-	22,599
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
Bcf Equivalents (Bcfe) (2)					
December 31, 2006	1,157.1	148.3	717.7	-	2,023.1
December 31, 2007	1,318.7	141.7	309.7	-	1,770.1
December 31, 2008	1,621.7	135.9	318.4	-	2,076.0
December 31, 2009	3,563.7	969.0	385.2	-	4,917.9

(1) Includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(2) Billion cubic feet or billion cubic feet equivalent, as applicable. Natural gas equivalents are determined using the ratio of 6.0 thousand cubic feet of natural gas to 1.0 barrel of crude oil and condensate or natural gas liquids.
(3) Thousand barrels; includes crude oil and condensate and natural gas liquids.

For the twelve-month period ended December 31, 2009, total proved undeveloped reserves increased by 2,841.9 Bcfe to 4,917.9 Bcfe. Based on the new definition of proved undeveloped reserves and its applicability to large resource plays, EOG added significant proved undeveloped reserves in the Haynesville, Horn River, Barnett Combo and Marcellus shale plays. Purchases in place included proved undeveloped reserves from the Rocky Mountain property exchange and the acquisition of the Barnett Shale Combo Assets (see Note 17). During the year, EOG drilled and transferred approximately 176 Bcfe of proved undeveloped reserves to proved developed at a total capital cost of $280.5 million. EOG does not have a material amount of reserves that have remained undeveloped for five years or more.

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to EOG's natural gas and crude oil producing activities at December 31, 2009 and 2008:

	2009	2008
Proved properties	$ 23,097,568	$ 19,785,449
Unproved properties	1,516,743	1,018,180
Total	24,614,311	20,803,629
Accumulated depreciation, depletion and amortization	(9,479,525)	(7,952,608)
Net capitalized costs	**$ 15,134,786**	**$ 12,851,021**

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 the Accounting Standards Codification.

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.

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, 2009, 2008 and 2007:

	United States	Canada	Trinidad	Other International [1]	Total
2009					
Acquisition Costs of Properties					
Unproved [2]	$ 648,331	$ 17,806	$ 800	$ (311)	$ 666,626
Proved [3]	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 [4]	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 [5]	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
2007					
Acquisition Costs of Properties					
Unproved	$ 233,337	$ 45,842	$ (38)	$ (1,141)	$ 278,000
Proved	3,887	696	15,414	-	19,997
Subtotal	237,224	46,538	15,376	(1,141)	297,997
Exploration Costs	435,944	75,531	45,161	33,104	589,740
Development Costs [6]	2,358,258	263,547	91,242	(1,417)	2,711,630
Total	$ 3,031,426	$ 385,616	$ 151,779	$ 30,546	$ 3,599,367

(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 $35 million, related to the acquisition of Haynesville Assets.
(3) Includes non-cash acquisition costs of $353 million related to a property exchange transaction in the Rocky Mountain area.
(4) 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.
(5) 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.
(6) Includes Asset Retirement Costs of $22 million, $9 million, zero and zero for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

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, 2009, 2008 and 2007:

	United States	Canada	Trinidad	Other International [2]	Total
2009					
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids 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					
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids 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
2007					
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 3,026,929	$ 585,314	$ 352,877	$ 55,208	$ 4,020,328
Other	8,796	(105)	8	1	8,700
Total	3,035,725	585,209	352,885	55,209	4,029,028
Exploration Costs	116,152	15,500	7,577	11,216	150,445
Dry Hole Costs	83,160	5,349	19,350	7,523	115,382
Transportation Costs	136,630	8,880	-	6,726	152,236
Production Costs	454,164	137,003	45,634	3,381	640,182
Impairments	108,037	37,076	-	2,404	147,517
Depreciation, Depletion and Amortization	809,540	169,852	24,306	21,565	1,025,263
Income Before Income Taxes	1,328,042	211,549	256,018	2,394	1,798,003
Income Tax Provision	477,826	68,330	112,996	1,960	661,112
Results of Operations	$ 850,216	$ 143,219	$ 143,022	$ 434	$ 1,136,891

(1) Excludes gains or losses on mark to market 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, 2009.

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

The following table sets forth production costs per thousand cubic feet equivalent, excluding severance/production and ad valorem taxes, for the years ended December 31, 2009, 2008 and 2007:

Production Costs Per Unit	United States	Canada	Trinidad	Other International (1)	Composite
Year Ended December 31, 2009	$ 0.74	$ 1.40	$ 0.12	$ 1.74	$ 0.73
Year Ended December 31, 2008	$ 0.75	$ 1.34	$ 0.17	$ 1.23	$ 0.76
Year Ended December 31, 2007	$ 0.70	$ 1.37	$ 0.18	$ 0.38	$ 0.71

(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 natural gas and liquids 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 year 2009 and year-end prices for the years 2008 and 2007. It 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 natural gas and liquids 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 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.

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, 2009, 2008 and 2007:

	United States	Canada	Trinidad	Other International [1]	Total
2009					
Future cash inflows [2]	$ 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 [3]	$ 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
2007					
Future cash inflows [4]	$ 41,151,570	$ 8,783,187	$ 6,196,996	$ 133,844	$ 56,265,597
Future production costs	(11,449,082)	(2,766,329)	(630,556)	(29,022)	(14,874,989)
Future development costs	(2,716,181)	(493,772)	(385,406)	(8,049)	(3,603,408)
Future income taxes	(8,195,111)	(1,085,595)	(2,065,505)	(48,387)	(11,394,598)
Future net cash flows	18,791,196	4,437,491	3,115,529	48,386	26,392,602
Discount to present value at 10% annual rate	(9,326,881)	(2,002,808)	(1,276,573)	(4,718)	(12,610,980)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 9,464,315	$ 2,434,683	$ 1,838,956	$ 43,668	$ 13,781,622

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

(2) 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. 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.

(3) 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. 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.

(4) Estimated natural gas prices used to calculate 2007 future cash inflows for the United States, Canada, Trinidad and Other International were $6.79, $6.47, $4.29 and $10.05, respectively. Estimated liquids prices used to calculate 2007 future cash inflows for the United States, Canada, Trinidad and Other International were $78.13, $78.10, $86.11 and $84.20, respectively.

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, 2009:

	United States	Canada	Trinidad	Other International	Total
December 31, 2006	$ 5,149,485	$ 1,962,556	$ 1,244,649	$ 20,971	$ 8,377,661
Sales and transfers of oil and gas produced, net of production costs	(2,408,307)	(439,482)	(307,237)	(45,107)	(3,200,133)
Net changes in prices and production costs	3,397,803	747,389	961,686	76,223	5,183,101
Extensions, discoveries, additions and improved recovery, net of related costs	3,708,015	184,691	-	-	3,892,706
Development costs incurred	459,700	42,300	139,100	-	641,100
Revisions of estimated development cost	(2,547)	(56,336)	(57,498)	(70)	(116,451)
Revisions of previous quantity estimates	294,500	(135,562)	(57,680)	19,645	120,903
Accretion of discount	694,165	229,953	202,032	4,194	1,130,344
Net change in income taxes	(1,872,542)	(46,935)	(378,415)	(22,697)	(2,320,589)
Purchases of reserves in place	5,309	1,726	55,372	-	62,407
Sales of reserves in place	(47,151)	-	-	-	(47,151)
Changes in timing and other	85,885	(55,617)	36,947	(9,491)	57,724
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**

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
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 Before Income Taxes	$ 264,775	$ (23,556)	$ 4,557	$ 626,235
Income Tax Provision	106,065	(6,850)	361	225,808
Net Income Available to Common Stockholders	$ 158,710	$ (16,706)	$ 4,196	$ 400,427
Net Income Per Share Available to Common Stockholders (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
2008				
Net Operating Revenues	$ 1,134,018	$ 1,095,512	$ 3,263,886	$ 1,633,727
Operating Income	$ 380,720	$ 243,103	$ 2,392,183	$ 751,179
Income Before Income Taxes	$ 370,112	$ 247,383	$ 2,393,952	$ 735,092
Income Tax Provision	129,156	69,177	837,667	273,620
Net Income	240,956	178,206	1,556,285	461,472
Preferred Stock Dividends (2)	443	-	-	-
Net Income Available to Common Stockholders	$ 240,513	$ 178,206	$ 1,556,285	$ 461,472
Net Income Per Share Available to Common Stockholders (1)				
Basic	$ 0.98	$ 0.72	$ 6.30	$ 1.86
Diluted	$ 0.96	$ 0.71	$ 6.20	$ 1.84
Average Number of Common Shares				
Basic	245,430	246,536	247,155	247,672
Diluted	249,763	251,135	250,930	250,162

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

(2) Includes premium and fees associated with the repurchase of preferred stock in the first quarter of 2008. See Note 3 to Consolidated Financial Statements.

Schedule II

EOG RESOURCES, INC.

VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2009, 2008 and 2007

(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
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
2007								
Allowance deducted from Accounts Receivable	$	17,299	$	16	$	1,296	$	16,019

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 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, 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).
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, 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).
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).

Exhibit Number		Description
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)	-	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(d)	-	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(e)	-	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(f)	-	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(g)	-	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(h)	-	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).
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).

Exhibit Number		Description
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).
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).
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).
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).
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).
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).
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).
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).
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).

Exhibit Number		Description
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).
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).
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).
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).
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. Executive Officer Annual Bonus Plan (Exhibit C to EOG's Proxy Statement, filed March 29, 2001, with respect to EOG's 2001 Annual Meeting of Stockholders) (SEC File No. 001-09743).
10.13(a)	-	Revolving Credit Agreement, dated as of June 28, 2005, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
10.13(b)	-	First Amendment to Revolving Credit Agreement, dated as of June 21, 2006, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.13(c)	-	Second Amendment to Revolving Credit Agreement, dated as of May 18, 2007, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10.13(d)	-	Third Amendment to Revolving Credit Agreement, dated as of September 14, 2007, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).

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, 2009.
* 23.1	-	Consent of DeGolyer and MacNaughton.
* 23.2	-	Opinion of DeGolyer and MacNaughton dated February 4, 2010.
* 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, 2009, (ii) the Consolidated Balance Sheets - December 31, 2009 and 2008, (iii) the Consolidated Statements of Stockholders' Equity for Each of the Three Years in the Period Ended December 31, 2009, (iv) the Consolidated Statements of Cash Flows for Each of the Three Years in the Period Ended December 31, 2009 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.

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 25, 2010

By: /s/ TIMOTHY K. DRIGGERS
Timothy K. Driggers
Vice President and Chief Financial Officer
(Principal Financial and Accounting 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 25th day of February, 2010.

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 and 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)

QUANTITATIVE RECONCILIATION OF AFTER-TAX INTEREST EXPENSE (NON-GAAP), NET DEBT (NON-GAAP) AND TOTAL CAPITALIZATION (NON-GAAP) AS USED IN THE CALCULATIONS OF RETURN ON CAPITAL EMPLOYED (NON-GAAP) AND THE NET DEBT-TO-TOTAL CAPITALIZATION RATIO (NON-GAAP) TO INTEREST EXPENSE (GAAP), CURRENT AND LONG-TERM DEBT (GAAP) AND TOTAL CAPITALIZATION (GAAP), RESPECTIVELY (UNAUDITED; IN MILLIONS, EXCEPT RATIO DATA)

The following chart reconciles Interest Expense (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP) to After-Tax Interest Expense (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP), respectively, as used in the Return on Capital Employed (ROCE) and Net Debt-to-Total Capitalization ratio calculations. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who utilize After-Tax Interest Expense, Net Debt and Total Capitalization in their ROCE and Net Debt-to-Total Capitalization ratio calculations. EOG management uses this information for comparative purposes within the industry.

	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Return on Capital Employed and Net Debt-to-Total Capitalization Ratio											
Interest Expense	$ 100.9	$ 51.7	$ 46.8	$ 43.2	$ 62.5	$ 63.1	$ 58.7	$ 59.7	$ 45.1	$ 61.0	
Tax Benefit Imputed (based on 35%)	(35.3)	(18.1)	(16.4)	(15.1)	(21.9)	(22.1)	(20.5)	(20.9)	(15.8)	(21.4)	
After-Tax Interest Expense (Non-GAAP) - (a)	$ 65.6	$ 33.6	$ 30.4	$ 28.1	$ 40.6	$ 41.0	$ 38.2	$ 38.8	$ 29.3	$ 39.6	
Net Income - (b)	$ 546.6	$ 2,436.9	$1,089.9	$1,299.9	$1,259.6	$ 624.9	$ 430.1	$ 87.2	$ 398.6	$ 396.9	
Total Stockholders' Equity - (c)	$ 9,998.0	$ 9,014.5	$6,990.1	$5,599.7	$4,316.3	$2,945.4	$2,223.4	$1,672.4	$1,642.7	$1,380.9	$1,129.6
Current and Long-Term Debt - (d)	$ 2,797.0	$ 1,897.0	$1,185.0	$ 733.4	$ 985.1	$1,077.6	$1,108.9	$1,145.1	$ 856.0	$ 859.0	$ 990.3
Less: Cash	(685.8)	(331.3)	(54.2)	(218.3)	(643.8)	(21.0)	(4.4)	(9.8)	(2.5)	(20.2)	(24.8)
Net Debt (Non-GAAP) - (e)	$ 2,111.2	$ 1,565.7	$1,130.8	$ 515.1	$ 341.3	$1,056.6	$1,104.5	$1,135.3	$ 853.5	$ 838.8	$ 965.5
Total Capitalization (GAAP) - (c) + (d)	$12,795.0	$10,911.5	$8,175.1	$6,333.1	$5,301.4	$4,023.0	$3,332.3	$2,817.5	$2,498.7	$2,239.9	$2,119.9
Total Capitalization (Non-GAAP) - (c) + (e)	$12,109.2	$10,580.2	$8,120.9	$6,114.8	$4,657.6	$4,002.0	$3,327.9	$2,807.7	$2,496.2	$2,219.7	$2,095.1
Average Total Capitalization (Non-GAAP)* - (f)	$11,344.7	$ 9,350.6	$7,117.9	$5,386.2	$4,329.8	$3,665.0	$3,067.8	$2,652.0	$2,358.0	$2,157.4	
Return on Capital Employed (ROCE) (Non-GAAP) - [(a) + (b)] / (f)	5.4%	26.4%	15.7%	24.7%	30.0%	18.2%	15.3%	4.8%	18.1%	20.2%	
Average ROCE (Non-GAAP) 2000-2009	17.9%										
Debt-to-Total Capitalization (GAAP) - (d) / [(c) + (d)]	21.9%										
Net Debt-to-Total Capitalization (Non-GAAP) - (e) / [(c) + (e)]	17.4%										

*Average of "Total Capitalization (Non-GAAP)" for the current and immediately preceding year

Below are definitions for certain quantitative measures used in the Letter to Stockholders:

Stock Appreciation

Stock appreciation represents the increase in stock price during the period and is expressed as a percentage of the stock price at the beginning of the period.

Total Reserve Replacement Costs from All Sources

Total reserve replacement costs from all sources is the ratio of net reserve additions from drilling, acquisitions, total revisions and dispositions to total production.

GLOSSARY OF TERMS

Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
$/Bbl	Dollars per barrel
$/Mcf	Dollars per thousand cubic feet
MBbld	Thousand barrels per day
MMboe	Million barrels of oil equivalent
MMcfd	Million cubic feet per day
MMcfed	Million cubic feet equivalent per day
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
S&P	Standard and Poor's
Tcfe	Trillion cubic feet equivalent

OFFICERS AND DIRECTORS

Directors

George A. Alcorn(1)
Houston, Texas
President, Alcorn Exploration, Inc.

Charles R. Crisp(2)
Houston, Texas
Investments

James C. Day(3)
Sugar Land, Texas
Retired Chairman of the Board and
Chief Executive Officer,
Noble Corporation

Mark G. Papa
Chairman of the Board and
Chief Executive Officer,
EOG Resources, Inc.

H. Leighton Steward(4)
Cody, Wyoming
Author-Partner, Sugar Busters, LLC

Donald F. Textor(5)
Locust Valley, New York
Portfolio Manager, Dorset Management
Corporation and Partner, Knott Partners
Management LLC

Frank G. Wisner(6)
New York, New York
International Affairs Advisor,
Patton Boggs LLP

Officers
(including key subsidiaries)

Mark G. Papa
Chairman of the Board and
Chief Executive Officer

Loren M. Leiker
Senior Executive Vice President, Exploration

Gary L. Thomas
Senior Executive Vice President, Operations

Kurt D. Doerr
Executive Vice President and
General Manager, Denver

Robert K. Garrison
Executive Vice President, Exploration

William R. Thomas
Executive Vice President and
General Manager, Fort Worth

Frederick J. Plaeger, II
Senior Vice President and General Counsel

Paul Arnott
Vice President and General Manager,
EOG Resources Canada Inc.

Maire A. Baldwin
Vice President, Investor Relations

Sandeep Bhakhri
Vice President and Chief Information Officer

Timothy K. Driggers
Vice President and Chief Financial Officer

Kenneth E. Dunn
Vice President and General Manager,
Corpus Christi

Patricia L. Edwards
Vice President, Human Resources and
Administration

Marc R. Eschenburg
Vice President, Marketing and
Regulatory Affairs

David J. Griffiths
General Manager, EOG Resources
United Kingdom Limited

Kevin S. Hanzel
Vice President, Audit

Lloyd W. Helms, Jr.
Vice President and General Manager,
Canada Shale Project

Raymond L. Ingle
Vice President and General Manager,
Midstream

Ann D. Janssen
Vice President, Accounting

Ernest J. LaFlure
Vice President and General Manager, Tyler

Helen Y. Lim
Vice President and Treasurer

Lindell L. Looger
Vice President and General Manager,
International
President, EOG Resources International, Inc.

Tony C. Maranto
Vice President and General Manager,
Oklahoma City

Richard A. Ott
Vice President, Tax

Curtis C. Parsons
Vice President and General Manager,
Fort Worth North

Sammy G. Pickering
Managing Director, EOG Resources
Trinidad Limited

Gary L. Pitts
Vice President and General Manager,
Midland

Gary L. Smith
Vice President and General Manager,
Pittsburgh

Robert C. Smith
Vice President, Drilling

J. Pat Woods
Vice President and General Manager,
Fort Worth South

Michael P. Donaldson
Corporate Secretary

James C. Fletcher
Controller, Land Administration

John H. Haskins
Controller, International Accounting

Janet B. Johnson
Controller, Compliance and Controls

Joseph C. Landry
Controller, Operations Accounting

Gary Y. Peng
Controller, Financial Reporting

Robert L. West
Controller, Financial Planning

(1) Chairman, Compensation Committee; Member, Audit and Nominating and Governance Committees

(2) Member, Audit, Compensation and Nominating and Governance Committees; 2010 Presiding Director

(3) Member, Audit, Compensation and Nominating and Governance Committees; 2009 Presiding Director

(4) Member, Audit, Compensation and Nominating and Governance Committees

(5) Chairman, Audit Committee; Member, Compensation and Nominating and Governance Committees

(6) Chairman, Nominating and Governance Committee; Member, Audit and Compensation Committees

STOCKHOLDER INFORMATION

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Houston, Texas 77002
P.O. Box 4362
Houston, Texas 77210-4362
(713) 651-7000
Toll Free: (877) 363-EOGR
www.eogresources.com

Common Stock Exchange Listing
New York Stock Exchange
Ticker Symbol: EOG
Common Stock Outstanding at December 31, 2009: 252,508,652 shares

Transfer Agent
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, Rhode Island 02940-3078
Toll Free: (877) 282-1168
Outside U.S.: (781) 575-2000
www.computershare.com
Hearing Impaired: TDD (800) 952-9245

2010 Annual Meeting of Stockholders

EOG's 2010 Annual Meeting of Stockholders will be held at 3 p.m., Houston time, at the Doubletree Hotel, 400 Dallas Street, Houston, Texas 77002, on Wednesday, April 28, 2010. Information with respect to the annual meeting is contained in the proxy statement sent with this Annual Report to holders of record of EOG Common Stock. This Annual Report is not to be considered a part of EOG's proxy soliciting material for the annual meeting.

Certifications

In 2009, EOG's Chief Executive Officer (CEO) provided to the New York Stock Exchange (NYSE) the annual CEO certification regarding EOG's compliance with the NYSE's corporate governance listing standards. In addition, EOG's CEO (principal executive officer) and EOG's principal financial officer filed with the United States Securities and Exchange Commission (SEC) all certifications required in EOG's SEC reports for fiscal year 2009.

Additional Information

Additional copies of this Annual Report (as well as copies of any of the exhibits to the Form 10-K included herein) are available upon request by calling (877) 363-EOGR; by writing EOG's Corporate Secretary at EOG Resources, Inc., 1111 Bagby, Sky Lobby 2, Houston, Texas 77002; or by visiting the EOG website at www.eogresources.com. Quarterly and annual earnings press release information for EOG and EOG's SEC filings also can be accessed through EOG's website.

Financial analysts and investors who need additional information should visit the EOG website at www.eogresources.com or contact EOG's Investor Relations department at (713) 651-7000.

OUR EMPLOYEES Harold Abernathy Ismael Abila Raymie Abney Renesha Abraham Erlinda Abrego Linda Acosta Kimberly Adams Sharon Adams Michael Adrion Tonya Adrion Amer Afifi Candelario Aguilar Amit Ahuja
Tanvi Ahuja Roberto Alaniz Jennifer Alba Melissa Albert Myrna Albright Mahdee Aleem Cesar Aleman Janice Alexander Patrick Alexander Joseph Alexander Sheena Ali Gabriella Aliberti Raymond Allbee Kenneth Allemand
Kenneth Allen Susan Allen Andrew Allison Ariana Alvarez Douglas Amburn Martin Amorortu Junior Andall Amanda Anderson Cathy Anderson Donna Anderson Jeremy Anderson Karen Anderson William Anderson
Chris Anderson Joseph Anderson Francisca Andreassen Nathan Andrews Catherine Aniello Jim Anschutz Barbara Anselm Osman Apaydin Sandra Apodaca Andres Arambula Blaine Ardelian Mario Arevalo Rene Argueta
Erick Armentrout Ralph Armentrout Donald Armstrong Cody Arnold Lance Arnold Paul Arnott Leslie Ashby Gerald Ashcraft Dana Assen Carlotta Audain-Campbell Marie Auger Richard Austin Terry Avery Mario Avila
Sammie Bagley Amanda Bailey Diane Bailey John Bailey Michael Bailey Michael Bailey Steven Bailey Kathryn Bailey Leona Bailey Amanda Baker Kevin Baker Lanny Baker Trent Baker Bryan Baldwin Maire Baldwin
Lorraine Baline Jerry Ball John Ball William Ball Blaine Balmer Valeria Banks Bijay Banthia Brian Baptiste Kristian Baptiste Randy Barber Linda Barberousse Guy Bardwell Tarra Barker Judy Barlow Brett Barnes Cheryl Barnes
James Barnes Kelley Barnett Leslie Barney Daniel Barone Rosalinda Barragan Andrew Barrera Emilio Barrera Hector Barrera Anthony Barrett Jennifer Barron Amanda Bartlett Jerrett Bartlett Kelli Barton Leah Barton
Sandra Barton Michelle Bates Dale Bawol Crystal Baxter Richard Bayes Jessica Beaman Ana Beasley Megan Beatty Donna Beauchamp Michelle Beauchamp Jennifer Beavers Gary Beck Geff Beck John Becker Navneet Behl
Kelly Belanger Barbara Belcher Heath Bell Michael Bell Heather Bell Corallini Olynda Bello Viktor Belski Adriana Benavides Vicky Benavides Tammy Benishek Kristy Bennett Steven Bennett Amanda Bennett Tana Bennett
Gust Benninger Roy Benteau Andrew Bentley Melvin Bentley John Bergquist Martha Bernardini Kerry Bernas Timothy Berry Caroline Bertuzzi Berwin Best Brad Betsworth Sandeep Bhakhri Benjamin Biery Jerry Biggs
Albert Billman James Binegar Blaine Bischoff Sidney Bjorlie Camille Black Mindy Black Randolph Blackburn Ben Blackwelder Brad Blackwood Carolyn Bladek Sibyl Blankenship Phebe Blaylock Dana Blevins Teresa Block
Ronnie Blue Gary Blundell Stanley Blundell Jonathan Bocox Kenneth Boedeker Susan Boedeker David Boerm David Boisjolie Paul Boland Wendy Bone Alisa Booth Joshua Boren Vera Boren Susan Borgan Kyle Borrello
Stewart Bosch James Bouillion Deidra Bourland Steven Bowker Ashley Bowman Jamie Bowman John Boyd Lorne Brack Mary Bradford Al Bradley Diane Bradley Tom Bradley Bryan Brandon Laurie Brandon Cheryl Brashear
Ronald Braswell Natalie Brayton Larry Brazile Karyn Breeckner Mike Brietzke Susan Bright David Brinkerhoff Brad Briscoe Georgia Briscoe Terry Bristol Gary Britt Matthew Britt Rachel Britt Sonia Brittain Mary Brooke
Michael Brooks Timothy Broom Burt Broussard Amber Brown Brandon Brown Jeff Brown Roger Brown Winfred Brown Jennifer Brown Robert Brown John Bruch David Brunette Linda Bruster James Bucci Fayetta Burch
Kerry Burdett Darryl Burger Geoff Burkart Rick Burke Stephen Burke Wesley Burke Eric Burkholder John Burnette Shaun Burris Amanda Burt Laurie Burt Paul Burt Shelley Burt Richard Burton Sandra Burton Brandy Butler
Lee Butler Scott Buttross Gwen Buye Ron Buye Brant Buzbee Janice Byam Barry Byars Dustin Bynum Deborah Byrd Kenneth Byrd William Byrd Christina Byrom Kim Cadena Ronald Cafagna Brad Cage Robert Cahill
Min Cai Patricia Cain David Cain Jared Calder Christopher Caldwell Victoria Calhoun Ingrid Callender Howard Cameron Carleen Campbell Catherine Campbell David Campbell Stephen Campbell Daniel Canales
Charlotte Candler Louis Cann Stephanie Cano Joseph Cantu Julie Cao Emmett Capt Michael Caputi Joseph Caputo John Cardin Santos Cardona Courtney Carlton Skipper Carnes Ronald Carney Cary Carrabine
Darin Carrasco Noemi Carrillo Leland Carroll Robert Carroll Gary Carson Kristin Carson Carmeletha Carter Kenneth Carter Larry Carter Susan Carulli Curtis Carver David Carver Cathy Castaneda Nicholas Castaneda
Jesus Castillo Rebecca Castro-Lowe Nina Catalucci Dennis Cates Sharon Caudill Jonathan Cave Mike Cervantes David Chadwick Richard Chaffe Paula Chaffin Shelly Chan Lindsay Chandler John Chapman William Chapman
Narvin Charles Kathy Ann Charles-Sylvester Carrie Charlton Travis Charnetzki Andres Chavez Laura Chavez Thomas Chen Dong Chen Linda Chenoweth Julie Cherry Ross Cherry Jacob Chew Erin Childs Helen Chin
Janice Chin-wing Drayton Andrew Chodur Young Chon Tracey Chong-Ashing Erin Chorney Penny Chrisman Lorne Christal Beverly Christensen Kevin Christensen Michael Christensen Elnora Christoffersen Douglas Chrumka
Kamal Chunilal Scott Church Albert Clark John Clark Sandra Clark Terrence Clarke Eugene Clower Linda Cluiss Crystal Cobb Letitia Cobb Sherron Codogan Brett Coe Donna Coe Rachel Coe Bruce Coit Ruby Cole
Carolyn Coleman Clifton Coleman James Coleman Jeremy Coleman Steven Coleman Robert Coles Randel Collar Chuck Collier Daniel Collins Charles Colson Rene Concialdi Paul Connolly Erica Conroy Duane Cook
Karen Cook Lisa Cook Melanie Cook Michael Cooksey Tyler Coon Laura Cooper Michael Cooper Kevin Copeland Lisa Copeland Craig Cormany Neal Cormier Mike Cornell Paul Corrales Jonnathan Coston Roy Coston
Stephen Couch Tommy Coulter Yvette Counts Mary Courtney Leon Covell III David Covill Kim Cowherd Sara Cowles Mark Cox Russell Cox Tyler Cox Jack Cozart Jeff Crabbe Logan Craig Alicia Craigwell Malinda Crall
Douglas Cramer Garth Cramer Bette Cranford Janice Cravens Dee Cravy Nora Crawford Misti Creach Allen Cregg Robert Crim Stacie Crosby Rosa Crotty Barry Crowder Phyllis Croy Stephen Croy Herminia Cruz Terry Csere
Wade Cuch Valerie Culpepper Ferdinand Cumberbatch James Cunkelman Peter Cunningham Tracy Cunningham Anton Dach Jesse Daggett Jeff Dahl Qi Dai Vivian Dai Kenneth Dalton Wendy Dalton Fassil Daniel
Timothy Daniels Marsha Danzell Leandro Daponte Judy Dargin Roger Dart Stephanie Daugherty Doumonyo Daukoru Bryan David Richard Davidson Donna Davies David Davis Douglas Davis Dustin Davis Jodie Davis
Lawrence Davis Randall Davis Richard Day David Deal Rochelle deGuzman Howard Deis Jennifer Del Tatto Steven DeLand Chris Delcambre Gloria DelCampo James DelCampo Joseph DelCampo Brenda Dellinger
Zhen An Deng Amanda Dennis Bobby Dennis Brian Desmond Kent Devenport Clinton Devillier Isaac DeVilliers Ronald Devoll Otto Dick Debbie Dickey Gary Dill Eric Dille Trudy Dillon Pam DiValerio John Dixon Annette Dobson
Kurt Doerr Brian Dolezal Daniel Domingue Kimberly Dominguez Manuel Dominguez Kathryn Donaldson Michael Donaldson Daryl Doodnath Jeff Dort Timothy Dort Ashley Douglass Wallace Dow Richard Downey
Johnny Downing Hollie Downs John Downs Rebecca Doyle Patrick Draves Timothy Driggers Candy Driscoll Barbara Drosche Hans Dube Darrah Duchscherer Rafe Dudley Denis Dufresne Cynthia Duge Lucas Duke
James Dunford Kenneth Dunn George Dupre Brian Durman Robert Dysart Karen Ebbert Stacey Eddings James Edgeman Madeline Edgley Dianne Edwards Donald Edwards Patricia Edwards Tara Edwards
Danielle Edwards-Dupay Kurt Eggebrecht Tug Eiden Cynthia Einkauf Enoch Elizondo Jerome Ellard Terrence Elliot Edward Elliott Keith Elliott Jennifer Elliott Ashley Ellis Jerald Ellis Robert Ellis Steven Ellis Ty Ellis
Donna Ellsworth Lorena Ellsworth John Ellyson William Elmer Jerome Elmlinger Kivonda Elmore Anna England Taggart English Ronald Ensminger Karen Erwin Marc Eschenburg Douglas Esmond Amanda Espinosa
Jaime Espinosa Marcus Estes Sandra Estrada Albert Evans Betty Evans Carol Evans-Danver Robert Evanson Beverly Fabian Kathleen Fabra Clyde Faggett James Falconi Roger Falk Timothy Farnham Ryan Farquhar
Klinton Farrar Eileen Faulk Carol Faullon Rick Feger Richard Fehr Mike Felice Krista Felts Len Ferguson Olga Ferrell Matthew Fey Daniel Fischer James Fischer Jeanine Fisher Sharie Fisher Heather Fjeld David Fleming
Jason Fleniken Amber Fletcher James Fletcher Robert Fletcher Willam Fletcher Paul Florentino Criselda Flores Michael Flowers Clifford Fobes Richard Fobes James Folcik Neil Footh Nancy Ford Kirk Foreman Larry Formo
Lee Forrest Karen Forrester Edwin Forsman Cindy Forsyth Susan Forsyth Mark Fortuna Therese Foster Ilona Fournier Larry Fournier John Fowler Daniel Fox Brandon Fox Lonnie Fox Nancy Fox Charles Francis Jesse Francis
Charles Franck Lydia Franco Christine Frank Deborah Franklin Danny Frederick Ashley Freeman Brian Freeman Reginald Freestone Brandon Fretheim Judy Frey William Fricker Gerald Froidl David Frye Laura Fuentes
Jason Fulkerson Benjamin Fuller Timothy Fusselman Heather Gable Timothy Gable Jared Gabro Sharleen Gale Jeremy Galeski Chris Gallant Jesus Gallegos Barbara Ganong Stephen Garber Debra Garcia Jeremias Garcia
Nancy Garcia Vic Garcia Cody Gardiner Kaylene Gardner Michael Gardner Trevor Gardner Jennifer Garner Dwayne Garnett Matthew Garrison Robert Garrison Mark Garza Patricia Garza Lindsey Gates Mickenzie Gates
Richard Gauthier Debra Gay Marshall Gazette Maria Geerligs Jamie Gehringer Gregory Geis Jared Geis Virginia Gent Zola George Jim Gerlinger Karen Gibson Mark Gibson Owen Gibson Jeff Gigstad Kenney Gilbreath
Emily Gillis Yvonne Gilmore Marilyn Giroir Donny Glanton Elmo Glover Michael Goad Anelia Gogova Tracy Goich-Peterson Jeff Goldberg Jessica Goldsmith Scott Goldsmith Gregg Gomez Derek Gonet Melinda Gonor
Evan Gonzalez Jose Gonzalez Juanita Gonzalez Mary Goode Ollie Goodwin Freddie Gordon Stephen Gordon Casey Gordy Linda Goroniuk Mark Gorski Lisa Gosine-Alleyne Richard Goulet Sam Governale Amy Graham
Danny Graham Donald Grant Dortha Gray James Gray Katherine Gray Michael Gray Mitchell Gray Pamela Gray Betty Green Bryan Green Jayne Green Karen Greengrass Norma Greenlee Rebecca Greenwood James Gregory
Leslie Griffin Stanley Grimes Carrie Grin Mary Grisaffi Lisa Groen Wayne Groo Nicholas Groves Judy Guebara Joseph Guerrero Evelyn Guess Carla Guillaume-Escalante John Guillot Michelle Gummelt Kevin Gunder
Randy Gustin Shaun Guthrie Laura Guzman Dalan Haase Natalie Haase Allen Hacking Jody Hadden William Hadley Kenneth Haggard Simret Hagos Tammy Hajovsky Alex Hale Kent Hale Leta Hale Callaway Hall Durk Hall
Kelly Hall Matthew Hall Vivi Ann Hall Robert Halverson Ronny Halvorson Aarne Hamalainen Kenna Hambor Chris Hames Debra Hamilton Lee-Anna Hamilton Sabrina Hamilton Phillip Hampton Debbra Hamre Jamie Hanafy
Kirk Hanberg Donna Haney Cynthia Hanselman Leo Hanselman Susan Hanselman Andrew Hanson Kevin Hanzel Ricky Hardaway Bart Hardman Tim Hargrove Sean Harlan Jeffery Harmon Robert Harp Dorothy Harper
Rachel Harrell Mitchell Harriman Etta Harris Jamie Harris Kristina Harris Sherry Harris Dianne Harris Jacob Harrison Pamela Harrison Steven Harrison William Harrison IV Burton Hartley Lance Hartwell Stephen Haskell
Warren Haskell John Haskins Mark Hately James Hatfield Tammy Hatfield Ricky Hathaway Michele Hatz Gina Hauck Debbie Haugen Jeanne Hawkes Erin Hawkins Gordon Haycraft Brian Hayes William Haynes Britt Hazelbush
Yong He Brent Hecht Michael Heil Lloyd Helms Sherron Helton Jennifer Henderson Bryan Hendricks Cody Hendricks Lois Hendricks Dustin Henline Bryan Hennigan James Henning James Henry Cory Hepburn Conrad Hergert
Alfredo Hernandez Eduardo Hernandez Rosalinda Hernandez Irene Herrera Billy Hester Tom Heydt Michael Heymann Becky Hicks Edward Hicks Jade Hicks Vicki Hietpas John Hill Van Hill Elise Hillman Stephen Himes
Robert Hinsley Kathryn Hinson Luke Hise Linda Hoagland Thanh Hoang Cecil Hodges Randy Hodgins Chris Hoefer Trevor Hoff Darby Hoffman Deanna Hoffman James Hoffman Myron Hoffman Margaret Hogan Edward Hohos
Derek Holeman Bryan Holgate Danny Holgate Jared Holgate Kasey Holland Sara Holland Nathan Hollek James Holley Jayne Hollier Wendell Holman Brant Holmes Derrik Holmes Kelli Holmes Mitchell Holmes Justin Holsworth
June Holt Wayne Holt Shay Holte Rhonda Holtgreive Erich Holzer Blake Hopkins Ashraful Hoque Garland Horak Jerry Horn Stacy Horn Kimberly Horrocks Helen Hosein-Mulloon Gary Don House Marion Houser III
David Houston Rick Hovland Glenn Howard Stephen Howell Karly Howerton Andrew Hoyle Donna Hradil LiYing Hsu Jack Huang Sean Huang Robert Hubbert Michael Huber Frank Hudec John Hudec Brandy Hudson
Randall Hulme Deanne Hulquist Robert Humphreys Wan-Hsiang Hung Patricia Hunt Lisa Hunter Michael Huntington Douglas Hurlbut Timothy Hutchins Mazher Ibrahim Marie Ice Lee Icenhower Diana Igleheart Silvia Iglesias
Jack Imboden Raymond Ingle Greg Ingram Kathleen Insley Michael Isaacs Allan Itz Elizabeth Ivers Diana Jablonski Amber Jackson Herschel Jackson Karl Jackson Kenneth Jackson L.J. Jackson Melinda Jackson
Robert Jackson Ronald Jackson Greg Jackson Gregory Jacobsen Robert Jakeway William Jakeway George James Ann Janssen Darryl Janssen Tracey Jarmin Renee Jarratt Lonnie Jeannerett Donna Jenkins Ronny Jenkins
Donna Jensen Tessa Jigmeddorj M. Teresa Jimenez Ling Jin Bruce Johnson Byron Johnson Charles Johnson Corby Johnson Cynthia Johnson David Johnson Deborah Johnson Derek Johnson Donna Johnson Jacob Johnson
Janet Johnson Sonya Johnson Barrie Johnson David Johnston Patricia Johnston Jason Johnstone John Joiner Casey Jones Gregg Jones Linda Jones Patricia Jones Sherry Jones Emile Jones Tiffany Jones Jon Jorgenson
James Joyce LaTonya Judon Sheri Jurecek Henry Kane Ronald Kane Teresa Kaplan Terrence Karka Olaf Karlsen Keith Karow Janene Kauffman Herb Kautzsch Dale Keeley Steven Keenan Thomas Keetley Lex Keim
Kenneth Kelley Theodore Kelly Howard Kemp John Kennah Wilbur Kennedy Tammy Kennedy-Andrews James Kerbow Paula Kettle Madiha Khan Sharif Khan Amanda Khan Shazeeda Khan-Seemungal Madiha Khurshid
Robert Kidney Allison Kidwell Omar Kilday George Killmer Billy Kimbro Nancy Kimbro Ashley Kinder Henry Kindschi Richard King Rick King Kendall Kingsland Melinda Kinkel Jodi Kipp Christopher Kirgan Carol Kirksey
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