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

Form 10-K

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

For the fiscal year ended December 31, 2005

☐ **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.)

333 Clay Street, Suite 4200, Houston, Texas 77002-7361
(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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated filer ☐

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 February 17, 2006 and 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 February 17, 2006: $17,354,275,342 and as of June 30, 2005: $13,626,764,801.

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, on February 17, 2006, Shares Outstanding: 242,547,524.

Documents incorporated by reference. Portions of the following document are incorporated by reference into the indicated parts of this report: Proxy Statement for the May 2, 2006 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2005 (Proxy Statement) - Part III.

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PART I

ITEM 1. ***Business***

General

EOG Resources, Inc. (EOG), a Delaware corporation organized in 1985, together with its subsidiaries, 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, offshore Trinidad, the United Kingdom North Sea 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 all amendments to those reports are made available, free of charge, through its website, as soon as reasonably practicable after such reports have been filed with the Securities and Exchange Commission (SEC). EOG's website address is http://www.eogresources.com.

At December 31, 2005, EOG's total estimated net proved reserves were 6,194 billion cubic feet equivalent (Bcfe), of which 5,557 billion cubic feet (Bcf) were natural gas reserves and 106 million barrels (MMBbl), or 637 Bcfe, were crude oil, condensate and natural gas liquids reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 56% of EOG's reserves (on a natural gas equivalent basis) were located in the United States, 22% in Canada, 21% in Trinidad and 1% in the United Kingdom North Sea. As of December 31, 2005, EOG employed approximately 1,400 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 its drilling activity toward natural gas deliverability in addition to natural gas reserve replacement and to a lesser extent crude oil exploration and exploitation. 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, and formation logging techniques and reservoir fracturing methods. These advanced technologies are used, as appropriate, throughout EOG to reduce the risks associated with all aspects of oil and gas reserve exploration, exploitation and development. 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 tactical acquisitions that result in additional economies of scale or land positions with 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, 2005, 88% of EOG's net proved United States and Canada reserves (on a natural gas equivalent basis) were natural gas and 12% were crude oil, 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 application of new processes and technologies. EOG also maintains an active exploration program designed to extend fields and add new trends to its broad portfolio. The following is a summary of significant developments during 2005 and certain 2006 plans for EOG's United States and Canada operations.

United States. During 2005, EOG continued its success in the prolific Barnett Shale play in North Texas with excellent drilling results plus significant growth in production and an increased acreage position. EOG drilled 88 net horizontal wells and grew production to approximately 100 million cubic feet per day (MMcfd), net by year-end. EOG made several significant gas discoveries, extending the trend to the west of Fort Worth. EOG increased its acreage position in the Barnett Shale play to over 500,000 acres during 2005 and may add acreage in this prolific play during 2006. EOG had 12 drilling rigs operating at year-end 2005, and plans to increase the number of rigs throughout 2006. EOG plans to drill approximately 210 gross Barnett Shale wells in 2006, which will continue EOG's strong production growth from the play. EOG is positioned for significant production and reserve growth in the Barnett Shale play for many more years.

In the Permian Basin, EOG exploited a successful Permo-Penn carbonate play and maintained an active horizontal drilling program in the Devonian formation of West Texas. Additionally, two new plays in Southeast New Mexico were deemed successful - a horizontal Wolfcamp play where EOG drilled six successful wells in 2005 and controls approximately 35,000 net acres and a horizontal Bone Spring shelf play where five successful wells were drilled in 2005 and EOG controls approximately 15,000 net acres. EOG drilled 54 net wells in the Permian Basin in 2005 and net production averaged 92 MMcfd of natural gas and 7.9 thousand barrels per day (MBbld) of crude oil, condensate and natural gas liquids. EOG has assembled an acreage position of over 130,000 net acres in several other growth plays that are currently being tested by drilling. With success, these plays will move into the exploitation phase in mid-to-late 2006.

EOG continued to intensify its activities in the Rocky Mountain area, drilling 119 net wells during 2005, including 47 net wells in the Uinta Basin, Utah, nine net wells on the LaBarge Platform, Wyoming, 41 net wells on the Moxa Arch, Wyoming, and seven net wells in the Williston Basin. The net average daily production from the Rocky Mountain area was 141 MMcfd of natural gas and 7.5 MBbld of crude oil, condensate and natural gas liquids. EOG expects to continue increasing drilling activity in these core areas during 2006, while maintaining a very active exploration program.

In the Mid-Continent area, EOG drilled 137 net wells in its core areas in 2005, most notably the Hugoton-Deep play in the Oklahoma Panhandle and the Cleveland Horizontal play in the Texas Panhandle. The net average daily production was 79 MMcfd of natural gas and 2.1 MBbld of crude oil and condensate. EOG expanded its Hugoton-Deep program by approximately 900,000 acres and 1,300 square miles of 3-D seismic through the consummation of a 10-year joint venture with Anadarko Petroleum Company. In its Cleveland horizontal program, EOG has drilled 120 net wells since 2003 and expects to drill another 50 net wells in 2006. During 2005, EOG acquired new leases on over 8,000 net acres, increasing its position to approximately 130,000 net acres available to drill for Cleveland and high potential Morrow accumulations. In addition to these two areas, EOG will continue drilling in the Texas Panhandle area and pursue exploration prospects throughout the Mid-Continent area.

The Upper Gulf Coast continues to be a significant growth area for EOG where 2005 production averaged 113 MMcfd of natural gas and 3.1 MBbld of crude oil, condensate and natural gas liquids. EOG drilled 24 wells in the Sligo Field in 2005 and anticipates drilling an equal number of wells in both 2006 and 2007. The expanded Cotton Valley development program continues with five wells drilled in 2005 and 12 wells planned for 2006. Horizontal drilling is now being deployed in a new operating area in the Spider Field, North Louisiana, where five wells were drilled in 2005 and 13 are planned for 2006. Another new growth area is the Hosston trend in Mississippi where five wells were drilled in 2005 and 10 wells are planned for 2006. EOG will continue to develop growth opportunities in East Texas, North Louisiana and Mississippi and will test several high potential prospects in the Lower Gulf Coast areas of Texas and Louisiana during 2006.

EOG continues to have excellent success in South Texas where EOG drilled 76 net wells in 2005. The area averaged net production of 181 MMcfd of natural gas and 6.0 MBbld of crude oil, condensate and natural gas liquids. This represents the fourth consecutive year-over-year increase. The activity was focused in Webb, Zapata, San Patricio, Lavaca, Duval and other counties, where EOG executed successful drilling programs in the Lobo, Roleta, Reklaw, Frio and Wilcox plays. Significant activity in these areas resulted from successful extensions of existing plays, including the Frio trend in San Patricio and Nueces Counties, and the Lobo and Roleta trends in Webb and Zapata Counties. EOG successfully added new lease positions and 3-D seismic in 2005 to sustain drilling through 2006 and beyond.

In 2005, EOG drilled 90 net wells in the Appalachian area. Net production averaged 20 MMcfd of natural gas and 100 barrels per day (Bbld) of crude oil and condensate. EOG has reduced its focus on the Trenton Black River and has expanded the development of intermediate depth Mississippian and Ordovician plays. EOG expects to drill 85 net wells in 2006 to further expand the shallow and intermediate plays and will continue to focus on the expansion and development of higher impact, multiple-well plays.

During 2005, EOG's net production in the Gulf of Mexico averaged 41 MMcfd of natural gas and 1.1 MBbld of crude oil, condensate and natural gas liquids. Four shelf fields (Eugene Island 135, Matagorda Island 623, High Island 206, and Mustang Island 759) accounted for over 70% of this production. Due to Hurricanes Katrina and Rita, 2005 net production decreased an average of 4 MMcfd and 60 barrels of condensate per day (Bcpd). At year-end, a net 6 MMcfd and 98 Bcpd remained shut-in. This shut-in production is projected to be online by mid-year 2006. During 2005, EOG drilled six gross wells, resulting in four discoveries. The four successful wells, two at Grand Isle 94 and one each at Mustang Island 762 and High Island A-443, resulted in a net production increase of 8 MMcfd. A similar level of activity is planned in 2006.

At December 31, 2005, EOG held approximately 2,805,000 net undeveloped acres in the United States.

Canada. In Canada, EOG conducts operations through its subsidiary EOG Resources Canada, Inc. (EOGRC) from offices in Calgary, Alberta. During 2005, EOGRC continued its successful, shallow, natural gas strategy in Western Canada. An unusually wet summer resulted in surface conditions that restricted the overall drilling program whereby a total of 960 gross wells were drilled in 2005. Several soft access shallow natural gas areas will be drilled on the winter frost early in 2006 and will increase EOGRC's 2006 drilling program to 1,200 wells. The 2005 shallow natural gas drilling program included 208 gross Horseshoe Canyon dry coalbed methane wells. EOGRC's net production during 2005 averaged 228 MMcfd of natural gas, and 3.3 MBbld of crude oil, condensate and natural gas liquids. Key producing areas in the Western Canadian Sedimentary Basin are the Southeast Alberta/Southwest Saskatchewan shallow natural gas trends including Drumheller and Twining areas, and the Grand Prairie/Wapiti areas of Northwest Alberta. EOGRC's ongoing 2006 drilling activity will continue to be concentrated in these areas and will include a similar Horseshoe Canyon dry coalbed methane program. EOGRC will also participate in two high impact exploratory tests in the Northwest Territories during the first quarter of 2006, one on a separate new structure and one as delineation to our Summit Creek discovery, which was tested in early 2005.

At December 31, 2005, EOG held approximately 1,590,000 net undeveloped acres in Canada.

Operations Outside the United States and Canada

EOG has operations offshore Trinidad and the United Kingdom North Sea, and is evaluating additional exploration, exploitation and development opportunities in the United Kingdom, Trinidad and other international areas.

Trinidad. In November 1992, EOG, through its subsidiary, EOG Resources Trinidad Limited (EOGRT) acquired an exploration and production license with a 95% working interest, subject to a 5% overriding royalty interest, with an option to convert such overriding royalty interest to a 15% working interest in the South East Coast Consortium (SECC) Block offshore Trinidad. The Kiskadee, Ibis and Parula fields have been developed and are being produced. EOG is currently developing the Oilbird field and expects first production in the first quarter of 2007. The license covering the SECC Block will expire in December 2029. Effective February 3, 2005, the other participants in the SECC Block exercised their option to convert their 5% overriding royalty interest to a 15% working interest, thereby reducing EOG's working interest to 80%.

EOGRT and the other participants in the SECC Block signed a farm-in agreement covering the SECC Deep Ibis prospect with BP Trinidad and Tobago LLC in the fourth quarter of 2004. BP will pay the entire cost for drilling the exploratory well, which is expected to spud in the second quarter of 2006. EOG will retain a 50.6% working interest in the prospect and will develop the prospect, if successful.

In July 1996, EOG, through its subsidiary, EOG Resources Trinidad-U(a) Block Limited, signed a production sharing contract with the Government of Trinidad and Tobago for the Modified U(a) Block. EOG holds a 100% working interest in this block. The Osprey field was discovered in 1998 and commenced production in 2002.

Surplus processing and transportation capacity at the Pelican field facilities (owned and operated by a subsidiary of the other participants in the SECC Block) is being used to process and transport much of EOG's natural gas production and all of its crude oil and condensate production from the SECC and Modified U(a) Blocks. Crude oil and condensate from EOG's Trinidad operations are being sold to the Petroleum Company of Trinidad and Tobago.

In April 2002, EOG, through its subsidiary, EOG Resources Trinidad-LRL Unlimited, signed a production sharing contract with the Government of Trinidad and Tobago for the Lower Reverse "L" (LRL) Block which is adjacent to the SECC Block. EOG holds a 100% working interest in the LRL Block. In the fourth quarter of 2003, EOG drilled the first exploration well, LRL #1, on this block. The well was determined to be non-commercial. In November 2004, EOG drilled the LRL #2 well which encountered approximately 130 feet of net pay. In December 2004, the LRL #3 exploratory well was drilled and determined to be a dry hole. EOG plans to seek third parties to join in further exploration of the block in 2006.

In October 2002, EOG, through its subsidiary, EOG Resources Trinidad U(b) Block Unlimited, signed a production sharing contract with the Government of Trinidad and Tobago for the Modified U(b) Block which is also adjacent to the SECC Block. EOG holds a 55% working interest in and operates the Modified U(b) Block. Primera Oil & Gas Ltd., a Trinidadian company, holds the remaining 45% working interest. In September 2004, EOG drilled the first exploration well on this block, and the well was determined to be non-commercial. EOG will likely drill another well on the block in 2007.

In July 2005, EOG, through its subsidiary, EOG Resources Trinidad Block 4(a) Unlimited, signed a production sharing contract with the Government of Trinidad and Tobago for Block 4(a). EOG, as the operator, holds a 90% working interest in Block 4(a). Primera Block 4(a) Limited, a Trinidadian company, holds the remaining 10% working interest. In January 2006, EOG completed drilling its first successful exploratory well on this block and plans to drill another well in the first quarter of 2006. EOG intends to commence development work on this block by mid-2006 and is targeting mid-2009 for on-line production.

Natural gas from EOG's Trinidad operations is being sold to the National Gas Company of Trinidad and Tobago (NGC) under the following arrangements:

- Under the first take-or-pay contract, the expiration of which was extended in February 2005 from December 2008 to December 2018, natural gas is delivered to NGC for resale to Trinidad local markets. During 2005, EOG delivered net average production of 115 MMcfd of natural gas under this agreement. The extended contract, among other things, provides for a change in the pricing of wellhead natural gas volumes previously sold under a fixed price schedule with annual escalations. Prices are now partially dependent on Caribbean ammonia index prices and methanol prices.

- Under the second take-or-pay contract, which expires in 2017, EOG delivers to NGC approximately 60 MMcfd, gross, of natural gas which is resold to an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Caribbean Nitrogen Company Limited (CNCL). During 2005, 46 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC. The plant commenced production in June 2002 and currently produces approximately 1,900 metric tons of ammonia daily. EOGRT owns a 12% equity interest in CNCL. At December 31, 2005, EOGRT's investment in CNCL was $18 million. At December 31, 2005, CNCL had a long-term debt balance of $173 million, which is non-recourse to CNCL's shareholders. As part of the financing for CNCL, the shareholders have entered into a post-completion deficiency loan agreement with CNCL to fund the costs of operations, payment of principal and interest to the principal creditor and other cash deficiencies of CNCL up to $30 million, approximately $4 million of which is net to EOGRT's interest. 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, EOGRT is able to exercise significant influence over the operating and financial policies of CNCL and therefore, EOG accounts for the investment using the equity method. During 2005, EOG recognized equity income of $9 million and received cash dividends of $5 million from CNCL.

- Under a fifteen-year take-or-pay contract, which expires in 2019, EOG delivers to NGC approximately 60 MMcfd, gross, of natural gas which is resold to an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Nitrogen (2000) Unlimited (N2000). During 2005, 48 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC. The plant commenced production in August 2004 and currently produces approximately 2,100 metric tons of ammonia daily. EOG's subsidiary, EOG Resources NITRO2000 Ltd. (EOGNitro2000), owned a 10% equity interest in N2000 at December 31, 2005. In February 2005, EOGNitro2000 sold a portion of its ownership interest to one of the other shareholders, reducing EOGNitro2000's equity interest in N2000 to 10%. At December 31, 2004, EOGNitro2000's equity interest in N2000 was 23%. The sale resulted in a pre-tax gain of $2 million. At December 31, 2005, EOGNitro2000's investment in N2000 was $16 million. At December 31, 2005, N2000 had a long-term debt balance of $197 million, which is non-recourse to N2000's shareholders. As part of the loan agreement for the N2000 financing, affiliates of the shareholders have entered into a post-completion deficiency loan agreement with N2000 to fund the costs of operations, payment of principal and interest to the principal creditor and other cash deficiencies of N2000 up to $30 million, approximately $3 million of which is to be provided by the immediate parent company of EOGNitro2000. 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, EOGNitro2000 is able to exercise significant influence over the operating and financial policies of N2000 and therefore, EOG accounts for the investment using the equity method. During 2005, EOG recognized equity income of $7 million and received cash dividends of $2 million from N2000.

- Under a natural gas contract signed in January 2004, EOG is currently supplying approximately 100 MMcfd, gross, of natural gas to NGC, which is then being resold by NGC to a methanol plant located in Point Lisas, Trinidad. The plant, in which EOG does not own an interest, started production during the fourth quarter of 2005. Under this gas contract, EOG expects to ultimately supply approximately 94 MMcfd, gross, (60 MMcfd, net to EOG, based on current pricing and operating assumptions) for the first four years of the contract term and approximately 122 MMcfd, gross, (80 MMcfd, net to EOG, based on current pricing and operating assumptions) for the remaining term of the eleven-year contract.

- In February 2005, EOGRT executed a twenty-year take-or-pay contract with NGC LNG (Train 4) Limited, a subsidiary of NGC, for the supply of 30 MMcfd, gross, (17 MMcfd, net to EOG, based on current pricing and operating assumptions) of natural gas for use in a LNG plant in Point Fortin, Trinidad. The LNG plant began pre-start up operations in December 2005. During the first quarter of 2006, EOG expects to supply varying amounts of gas while NGC awaits the completion of pipelines from third party producers who also are under contract with NGC to supply incremental gas volumes into the LNG plant. EOG has no equity investment in the LNG plant.

In 2005, EOG's average net production from Trinidad was 231 MMcfd of natural gas and 4.5 MBbld of crude oil and condensate.

At December 31, 2005, EOG held approximately 261,600 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. In November 2003, a successful exploratory well, Arthur 1, was drilled in the Arthur field. Production from Arthur 1 commenced in January 2005. The Arthur 2 well was drilled during the first quarter of 2005 as an extension to the Arthur 1 discovery. Production from Arthur 2 commenced in July 2005. Another development well, Arthur 3, is planned for the first half of 2006 as an extension to the current discovery.

In the first half of 2005, EOGUK completed the drilling of two exploration wells, West Boulton and Polecat, which were both determined to be non-commercial.

In 2005, EOG delivered net average production of 39 MMcfd of natural gas in the United Kingdom.

At December 31, 2005, EOG held approximately 355,500 net undeveloped acres in the United Kingdom.

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. EOG's United States and Canada wellhead natural gas production is currently being sold on the spot market and under long-term natural gas contracts at market-responsive prices. In many instances, the long-term contract prices closely approximate the prices received for natural gas being sold on the spot market. In 2005, 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 pricing mechanisms for these contracts will remain the same in 2006. Also in Trinidad, in late December 2005, EOG began selling wellhead natural gas volumes under a new contract at prices partially dependent on the United States Henry Hub market prices. In the United Kingdom, wellhead natural gas production is currently being sold on the spot market.

Substantially all of EOG's wellhead crude oil and condensate is sold under various terms and arrangements at market-responsive prices.

During 2005, sales to a major integrated oil and gas company with investment grade credit ratings accounted for 11% of EOG's oil and gas revenues. No other individual purchaser accounted for 10% or more of EOG's oil and gas revenues for the same period. EOG does not believe that the loss of any single purchaser will have a material adverse effect on the financial condition or results of operations of EOG.

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 on a thousand cubic feet equivalent basis (Mcfe - natural gas equivalents are determined using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil, condensate or natural gas liquids) delivered during each of the three years in the period ended December 31, 2005.

	2005	2004	2003
Natural Gas Volumes (MMcfd)			
United States	718	631	638
Canada	228	212	165
Trinidad	231	186	152
United Kingdom	39	7	-
Total	**1,216**	**1,036**	**955**
Crude Oil and Condensate Volumes (MBbld)			
United States	21.5	21.1	18.5
Canada	2.4	2.7	2.3
Trinidad	4.5	3.6	2.4
United Kingdom	0.2	-	-
Total	**28.6**	**27.4**	**23.2**
Natural Gas Liquids Volumes (MBbld)			
United States	6.6	4.8	3.2
Canada	0.9	0.8	0.6
Total	**7.5**	**5.6**	**3.8**
Natural Gas Equivalent Volumes (MMcfed)(1)			
United States	886	786	768
Canada	248	233	183
Trinidad	259	207	166
United Kingdom	40	7	-
Total	**1,433**	**1,233**	**1,117**
Average Natural Gas Prices ($/Mcf)(2)			
United States	$ 7.86	$ 5.72	$ 5.06
Canada	7.14	5.22	4.66
Trinidad	2.20 (3)	1.51	1.35
United Kingdom	6.99	5.14	-
Composite	**6.62**	**4.86**	**4.40**
Average Crude Oil and Condensate Prices ($/Bbl)(2)			
United States	$ 54.57	$ 40.73	$ 30.24
Canada	50.49	37.68	28.54
Trinidad	57.36	39.12	28.88
United Kingdom	49.62	-	-
Composite	**54.63**	**40.22**	**29.92**
Average Natural Gas Liquids Prices ($/Bbl)(2)			
United States	$ 35.59	$ 27.79	$ 21.53
Canada	35.59	23.23	19.13
Composite	**35.59**	**27.13**	**21.13**

(1) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil, condensate and natural gas liquids.
(2) Dollars per thousand cubic feet or per barrel, as applicable.
(3) Includes $0.23 per Mcf as a result of a revenue adjustment related to an amended Trinidad take-or-pay contract.

Competition

EOG competes for reserve acquisitions and exploration/exploitation leases, licenses and concessions, frequently against companies with substantially larger financial and other resources. To the extent EOG's exploration budget is lower than that of certain of its competitors, EOG may be disadvantaged in effectively competing for certain reserves, leases, licenses and concessions. Competitive factors include price, contract terms and quality of service, including pipeline connection times and distribution efficiencies. In addition, EOG faces competition from other worldwide energy supplies, such as liquefied natural gas imported into the United States from other countries.

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 and regulate environmental and safety matters.

A substantial portion of EOG's oil and gas leases in Utah, 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 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, and 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 adversely affect EOG's interests.

In 2002, the D.C. Circuit reversed a 2000 district court decision and upheld a 1997 MMS gas valuation rule categorically denying allowances for post-production marketing costs such as long-term storage fees and marketer fees; however, the D.C. Circuit decision expressly allows firm demand charges to be deducted. Two trade associations had sought judicial review of the 1997 gas valuation rule and procured a favorable district court decision; however, the D.C. Circuit decision and denial of certorari by the Supreme Court ended the litigation in early 2003. On March 10, 2005, the MMS published a final rule further revising the gas valuation regulations. The 2005 gas rule revision clarifies the deductibility of transportation costs and adopts the 2004 oil valuation rule's cost of capital approach for calculating non-arm's length transportation allowances described below. EOG cannot predict what effect these changes will have on EOG operations but nothing significant is anticipated.

In 2004, the MMS further amended its royalty regulations governing the valuation of crude oil produced from federal leases. The MMS's 2000 oil valuation rule had replaced a set of valuation benchmarks based on posted prices and comparable sales with an indexing system based on spot prices at nearby market centers. Among other things, the 2000 oil valuation rule (like the 1997 gas valuation rule) also categorically disallowed deductions for post-production marketing costs. Two industry trade associations sought judicial review of the 2000 oil valuation rule, but voluntarily dismissed their suit after late 2002 negotiations led the MMS to amend its oil valuation rule further in 2004. The amended rule retained indexing for valuation but replaced spot prices with New York Mercantile Exchange future prices, except in the Rocky Mountain Region and California. The 2004 oil valuation rule also liberalized allowances for non-arm's length transportation arrangements by increasing the multiplier used for calculating the cost of capital. While the 2000 oil valuation rule was likely to increase EOG's royalty obligation somewhat, the 2004 oil valuation rule is likely to lessen that increase.

Sales of crude oil, condensate and natural gas liquids by EOG are made at unregulated market prices.

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 (NGPA). 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.

EOG owns, directly or indirectly, 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 adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

EOG's natural gas 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 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, 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 natural gas industry are considered from time to time by Congress, the state legislatures, the FERC, the state regulatory commissions and the federal and state courts. EOG cannot predict when or whether any such proposals or proceedings may become effective. It should also be noted that the natural 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 and 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. Under environmental 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 responsible under environmental laws and regulations for oil and gas properties in which EOG owns an interest but is not the operator. Compliance with such laws and regulations increases EOG's overall cost of business, but has not had a material adverse effect on EOG's operations or financial condition. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts that are material in relation to its total exploration and development expenditure program in order to comply with environmental laws and regulations, but inasmuch as such laws and regulations are frequently changed, EOG is unable to predict the ultimate cost of compliance. 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.

Canadian Regulation of Natural Gas and Crude Oil Production. The crude oil and natural 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 natural 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 complaints or economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for these commodities, increase EOG's costs and may have a material adverse impact on its operations.

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

In addition, each province has regulations that govern land tenure, royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from private 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. Crown royalties 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 or quality of the petroleum product produced.

Environmental Regulation - Canada. All phases of the crude oil and natural 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. 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. While compliance with such legislation can require significant expenditures, failure to comply with these environmental laws and regulations could result in the assessment of administrative, civil or criminal penalties, suspension or revocation of licenses and, in some instances, the issuance of injunctions to limit or cease operations.

Spills and releases from EOG's properties may have resulted or result in soil and groundwater contamination in certain locations. Such contamination is not unusual within the crude oil and natural gas industries. Any contamination found on, under or originating from the properties may be subject to remediation requirements under Canadian laws. 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.

In December 2002, the Canadian federal government ratified the Kyoto Protocol to the United Nations Framework Convention on Climate Change, which requires Canada to reduce its greenhouse gas emissions to 6% below 1990 levels over the 2008-2012 periods. The *Climate Change Plan for Canada*, which was released in November 2002, outlines, in very general terms, the approach the Canadian government intends to take to implement its emissions reduction commitment. The Canadian government issued a further climate change plan, *Moving Forward on Climate Change: A Plan for Honouring our Kyoto Commitment*, in April of 2005. Companies designated as Large Final Emitters of Greenhouse Gases (LFEs), which will include a number of companies in the oil and gas sector, will be assigned targets for emissions reduction. LFEs may meet their targets through investments in their own activities, the purchase of emissions credits from other emitters, investment in domestic offset credits, and the purchase of international credits. The Canadian government has renewed its promise that the cost to industry of compliance will not exceed $15 per tonne of carbon dioxide equivalent. The Canadian government has also committed that post-2012 emissions reduction targets will not make Canadian oil and gas production uncompetitive, and that industry will be consulted on the technical feasibility and economic impacts of targets for the period post-2012. The Canadian government's stated preference is to use the *Canadian Environmental Protection Act* to regulate industry where necessary. It is expected, however, that the Canadian government will largely delegate regulatory responsibility to the provinces through equivalency agreements, whereby a province will perform the necessary regulatory function if it has a substantively identical (or more onerous) program in place, as compared to that implemented by the Canadian government. The final rules, once known, could affect operations and profitability.

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 and the United Kingdom.

Other Matters

Energy Prices. Since EOG is primarily a natural gas producer, it is more significantly impacted by changes in prices for natural gas than changes in prices for crude oil, 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 75% increase in the average wellhead natural gas price for production in the United States and Canada received by EOG from 2002 to 2003, an increase of 12% from 2003 to 2004, and an increase of 37% from 2004 to 2005. In 2005, 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 pricing mechanisms for these contracts will remain the same in 2006. Also in Trinidad, in late December 2005, EOG began selling wellhead natural gas volumes under a new contract at prices partially dependent on the United States Henry Hub market prices. In the United Kingdom, wellhead natural gas production is currently being sold on the spot market. Crude oil and condensate prices also have fluctuated during the last three years. Due to the many uncertainties associated with the world political environment, the availabilities of other world wide 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, ammonia and methanol prices in the future.

Assuming a totally unhedged position for 2006, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2006 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf change in average wellhead natural gas price is approximately $24 million for net income and operating cash flow. EOG is not impacted as significantly by changing crude oil prices. EOG's price sensitivity in 2006 for each $1.00 per barrel change in average wellhead crude oil price is approximately $6 million for net income and operating cash flow. Summarized below and in Note 11 to Consolidated Financial Statements is information regarding EOG's current 2006 natural gas hedge position. As of February 22, 2006, EOG had no crude oil hedges.

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 collars and price swaps, as the 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 Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149, 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.

Presented below is a summary of EOG's 2006 natural gas financial collar and price swap contracts at February 22, 2006, with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units per day (MMBtud). As indicated, EOG does not have any financial collar or price swap contracts that cover periods beyond October 2006. EOG accounts for these collar and price swap contracts using mark-to-market accounting.

Natural Gas Financial Contracts

	Collar Contracts					Price Swap Contracts	
		Floor Price		Ceiling Price			
Month	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
February (closed)	50,000	$13.65 - 14.50	$14.05	$16.20 - 17.04	$16.59	-	-
March	50,000	13.50 - 14.30	13.87	15.95 - 17.05	16.46	170,000	$9.54
April	50,000	10.00 - 10.50	10.23	12.60 - 13.00	12.77	180,000	9.49
May	50,000	9.75 - 10.00	9.87	12.15 - 12.60	12.31	180,000	9.50
June	50,000	9.75 - 10.00	9.87	12.20 - 12.60	12.34	180,000	9.54
July	50,000	9.75 - 10.00	9.87	12.35 - 12.85	12.50	190,000	9.57
August	50,000	9.75 - 10.00	9.87	12.50 - 13.00	12.67	190,000	9.63
September	-	-	-	-	-	140,000	9.40
October	-	-	-	-	-	90,000	9.46

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. Offshore operations are subject to usual marine 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 the risks. Losses and liabilities arising from such events could reduce revenues and increase costs to EOG to the extent not covered by insurance. Please refer to ITEM 1A. *Risk Factors* beginning on page 14 for further discussion of the risks to which EOG is subject.

EOG's operations outside of the United States and Canada are subject to certain risks, including expropriation of assets, risks of increases in taxes and government royalties, 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.

Texas Severance Tax Exemption. Natural gas production from qualifying Texas wells spudded or completed after August 31, 1996, is entitled to use 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.

Common Stock Rights Agreement. On February 14, 2000, EOG's Board of Directors declared a dividend of one preferred share purchase right (a "Right," and the agreement governing the terms of such Rights, the "Rights Agreement") for each outstanding share of common stock, par value $0.01 per share. The Board of Directors has adopted this Rights Agreement to protect stockholders from coercive or otherwise unfair takeover tactics. The dividend was distributed to the stockholders of record on February 24, 2000. In accordance with the Rights Agreement, each share of common stock issued in connection with the two-for-one stock split effective March 1, 2005, also had one Right associated with it. Each Right, expiring February 24, 2010, represents a right to buy from EOG one hundredth (1/100) of a share of Series E Junior Participating Preferred Stock (Series E) for $90, once the Rights become exercisable. This portion of a Series E share will give the stockholder approximately the same dividend, voting, and liquidation rights as would one share of common stock. Prior to exercise, the Right does not give its holder any dividend, voting, or liquidation rights. If issued, each one hundredth (1/100) of a Series E share (i) will not be redeemable; (ii) will entitle holders to quarterly dividend payments of $0.01 per share, or an amount equal to the dividend paid on one share of common stock, whichever is greater; (iii) will entitle holders upon liquidation either to receive $1 per share or an amount equal to the payment made on one share of common stock, whichever is greater; (iv) will have the same voting power as one share of common stock; and (v) if shares of EOG's common stock are exchanged via merger, consolidation, or a similar transaction, will entitle holders to a per share payment equal to the payment made on one share of common stock.

The Rights will not be exercisable until ten days after a public announcement that a person or group has become an acquiring person (Acquiring Person) by obtaining beneficial ownership of 10% or more of EOG's common stock, or if earlier, ten business days (or a later date determined by EOG's Board of Directors before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if consummated, would result in that person or group becoming an Acquiring Person. On February 24, 2005, the Rights Agreement was amended to create an exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more, but less than 20%, of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the following requirements: (i) the institutional investor is described in Rule 13d-1(b)(1) promulgated under the Securities Exchange Act of 1934 and is eligible to report (and, if such institutional investor is the beneficial owner of greater than 5% of EOG's common stock, does in fact report) beneficial ownership of common stock on Schedule 13G; (ii) the institutional investor is not required to file a Schedule 13D (or any successor or comparable report) with respect to its beneficial ownership of EOG's common stock; (iii) the institutional investor does not beneficially own 15% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates other than those which, under published interpretations of the United States Securities and Exchange Commission or its staff, are eligible to file separate reports on Schedule 13G with respect to their beneficial ownership of EOG's common stock); and (iv) the institutional investor does not beneficially own 20% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates). On June 15, 2005, the Rights Agreement was amended again to revise the exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more but less than 30% of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the other requirements described above.

If a person or group becomes an Acquiring Person, all holders of Rights, except the Acquiring Person, may for $90, purchase shares of EOG's common stock with a market value of $180, based on the market price of the common stock prior to such acquisition. If EOG is later acquired in a merger or similar transaction after the Rights become exercisable, all holders of Rights except the Acquiring Person may, for $90, purchase shares of the acquiring corporation with a market value of $180 based on the market price of the acquiring corporation's stock, prior to such merger.

EOG's Board of Directors may redeem the Rights for $0.005 per Right at any time before any person or group becomes an Acquiring Person. If the Board of Directors redeems any Rights, it must redeem all of the Rights. Once the Rights are redeemed, the only right of the holders of Rights will be to receive the redemption price of $0.005 per Right. The redemption price has been adjusted for the two-for-one stock split effective March 1, 2005 and will be adjusted for any future stock split or stock dividends of EOG's common stock. After a person or group becomes an Acquiring Person, but before an Acquiring Person owns 50% or more of EOG's outstanding common stock, the Board of Directors may exchange the Rights for common stock or equivalent security at an exchange ratio of one share of common stock or an equivalent security for each such Right, other than Rights held by the Acquiring Person.

Preferred Stock. EOG currently has two authorized series of preferred stock. On February 14, 2000, EOG's Board of Directors, in connection with the Rights Agreement described above, authorized 1,500,000 shares of the Series E with the rights and preferences described above. On February 24, 2005, EOG's Board of Directors increased the authorized shares of Series E to 3,000,000 as a result of the two-for-one stock split of EOG's common stock effective March 1, 2005. Currently, there are no shares of the Series E outstanding.

On July 19, 2000, EOG's Board of Directors authorized 100,000 shares of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 Liquidation Preference per share (Series B). Dividends are payable on the shares only if declared by EOG's Board of Directors and will be cumulative. If declared, dividends will be payable at a rate of $71.95 per share, per year on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. EOG may redeem all or part of the Series B at any time beginning on December 15, 2009 at $1,000 per share, plus accrued and unpaid dividends. The Series B is not convertible into, or exchangeable for, common stock of EOG. There are 100,000 shares of the Series B currently outstanding.

Following the December 2004 redemption of all outstanding shares of EOG's Flexible Money Market Cumulative Preferred Stock, Series D, EOG filed a Certificate of Elimination with the Secretary of State of the State of Delaware on February 24, 2005 to eliminate the series from EOG's Restated Certificate of Incorporation, as amended.

Current Executive Officers of the Registrant

The current executive officers of EOG and their names and ages are as follows:

Name	Age	Position
Mark G. Papa	59	Chairman of the Board and Chief Executive Officer; Director
Edmund P. Segner, III	52	President and Chief of Staff; Director
Loren M. Leiker	52	Executive Vice President, Exploration and Development
Gary L. Thomas	56	Executive Vice President, Operations
Barry Hunsaker, Jr.	55	Senior Vice President and General Counsel
Timothy K. Driggers	44	Vice President and Chief Accounting 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, President in December 1996 and was President-North America Operations from February 1994 to September 1998. Mr. Papa joined Belco Petroleum Corporation, a predecessor of EOG, in 1981. Mr. Papa is EOG's principal executive officer.

Edmund P. Segner, III became President and Chief of Staff and Director of EOG in August 1999. He became Vice Chairman and Chief of Staff of EOG in September 1997. He was a director of EOG from January 1997 to October 1997. Mr. Segner is EOG's principal financial officer.

Loren M. Leiker was elected Executive Vice President, Exploration in May 1998 and was subsequently named Executive Vice President, Exploration and Development. He was previously Senior Vice President, Exploration. Mr. Leiker joined EOG in April 1989 as International Exploration Manager.

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

Barry Hunsaker, Jr. has been Senior Vice President and General Counsel since he joined EOG in May 1996.

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

There are no family relationships among the officers listed, and there are no arrangements or understandings pursuant to which any of them were elected as officers. Officers are appointed or elected annually by the Board of Directors at its meeting immediately prior to the Annual Meeting of Shareholders, each to hold office until the corresponding meeting of the Board in the next year or until a successor shall have been duly elected or appointed and shall have qualified.

ITEM 1A. *Risk Factors*

Our business faces many risks. The risks described below may not be the only risks we face. Additional risks that we do not yet know of, or that we currently think are immaterial, may also impair our business operations or financial results. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could suffer 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 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, condensate or natural gas liquids. Among the factors that can cause these price fluctuations are:

- the level of consumer demand;
- weather conditions;
- domestic drilling activity;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- worldwide economic and political conditions;
- the effect of worldwide energy conservation measures; and
- the nature and extent of governmental regulation and taxation.

Our cash flow and earnings depend to a great extent on the prevailing prices for natural gas and crude oil. Prolonged or substantial declines in these commodity prices may adversely affect our liquidity, the amount of cash flow we have available for capital expenditures and our ability to maintain our credit quality and access to the credit and capital markets.

Our ability to sell our crude oil and natural gas production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our crude oil and natural gas production depends on a number of factors beyond our control, including the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities or our failure to obtain these services on acceptable terms could materially harm our business. We deliver crude oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to market conditions or mechanical reasons, or may not be available to us in the future.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our underlying assumptions could cause the quantities of our reserves to be overstated.

Estimating quantities of proved crude oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions or changes of conditions could cause the quantities of our reserves to be overstated.

To prepare estimates of economically recoverable crude oil and natural gas reserves and future net cash flows, 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. Actual results most likely will vary from our estimates. Any significant variance could reduce our estimated quantities and present value of reserves.

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

The rate of production from crude oil and natural gas properties generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, acquire additional properties containing proved reserves, or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future crude oil and natural gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

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

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and result in a total loss of our investment. In addition, we often are uncertain as to the future cost or timing of drilling, completing and operating wells. Further, our drilling operations may be curtailed, delayed or canceled 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;
- compliance with environmental and other governmental requirements, which may increase our costs or restrict our activities; and
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and equipment.

We incur certain costs to comply with government regulations, especially regulations relating to environmental protection, 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 other countries in which we do business. We have and will continue to incur costs in our efforts to comply with the requirements of environmental and other regulations. Further, the crude oil and natural gas industry regulatory environment could change in ways that might substantially increase these costs.

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, local and foreign regulations relating to discharge of materials into, and protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from operations, subject us to liability for pollution damages, and require suspension or cessation of operations in affected areas. Changes in or additions to regulations regarding the protection of the environment could hurt our business.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities.

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters and other unforeseen occurrences such as blowouts, cratering, fires and loss of well control, which can damage or destroy wells or production facilities, injure or kill people, and damage property and the environment. Offshore operations are subject to usual marine perils, including hurricanes and other adverse weather conditions, and governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. 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 that we believe to be prudent. Losses and liabilities arising from such events could reduce our revenues and increase our costs to the extent not covered by insurance.

The occurrence of any of these events and any payments made as a result of such events and the liabilities related thereto, would reduce the funds available for exploration, drilling and production and could have a material adverse effect on our financial position or results of operations.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

From time to time, we use derivative instruments (primarily collars and price swaps) to hedge the impact of market fluctuations on natural gas and crude oil prices and net income and cash flow. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges. In addition, we are subject to risks associated with differences in prices at different locations, particularly where transportation constraints restrict our ability to deliver oil and gas volumes to the delivery point to which the hedging transaction is indexed.

If we acquire oil and gas properties, our failure to fully identify potential problems, to properly estimate reserves or production rates or costs, or to effectively integrate the acquired operations could seriously harm us.

From time to time, we seek to acquire oil and gas properties. Although we perform reviews of acquired properties that we believe are consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor do they permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs with respect to acquired properties. Actual results may vary substantially from those assumed in the estimates.

In addition, acquisitions may have adverse effects on our operating results, particularly during the periods in which the operations of acquired properties are being integrated into our ongoing operations.

Terrorist activities and military and other actions could adversely affect our business.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as the military or other actions taken in response to these acts, cause instability in the global financial and energy markets. The United States government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These actions could adversely affect us in unpredictable ways, including the disruption of fuel supplies and markets, increased volatility in crude oil and natural gas prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terror.

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 and other independent oil and gas companies for acquisition of oil and gas leases, properties and reserves, equipment and labor required to explore, develop and operate those properties and the marketing of crude oil and natural gas production. Higher recent crude oil and natural gas prices have increased the costs of properties available for acquisition and there are a greater number of companies with the financial resources to pursue acquisition opportunities.

Many of our competitors have financial and other resources substantially larger than those we possess and have established strategic long-term positions and maintain 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 bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas production, such as changing worldwide prices and levels of production, the cost and availability of alternative fuels and the application of government regulations. We also compete in attracting and retaining personnel, including geologists, geophysicists, engineers and other specialists.

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

We make, and will continue to make, substantial capital expenditures for the acquisition, development, production, exploration and abandonment of our oil and gas reserves. We intend to finance our capital expenditures primarily through cash flow from operations, commercial paper and to a lesser extent and if necessary, bank borrowings and public and private equity and debt offerings. Lower crude oil and natural gas prices, however, would reduce our cash flow and our access to the capital markets. Further, if the condition of the capital markets materially declines, we might not be able to obtain financing on terms we consider acceptable. In addition, a substantial rise in interest rates would decrease our net cash flows available for reinvestment.

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

In general, production from EOG's oil and gas properties declines as reserves are depleted. Except to the extent EOG acquires additional properties containing proved reserves or conducts successful exploration, exploitation and development activities, 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 and the costs incurred in so doing. 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, 2005. 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						
Texas	621,849	378,441	1,728,115	1,082,082	2,349,964	1,460,523
Wyoming	202,267	139,653	408,555	290,219	610,822	429,872
Oklahoma	286,153	212,405	252,182	149,034	538,335	361,439
Pennsylvania	82,416	70,779	177,695	159,314	260,111	230,093
New Mexico	101,332	66,690	251,676	155,027	353,008	221,717
Utah	83,739	57,308	228,702	141,686	312,441	198,994
Offshore Gulf of Mexico	191,959	70,036	153,855	85,682	345,814	155,718
Montana	145,030	14,063	202,334	137,921	347,364	151,984
Nevada	-	-	123,353	123,353	123,353	123,353
West Virginia	46,816	39,285	101,981	67,794	148,797	107,079
Ohio	61,753	58,341	36,774	35,571	98,527	93,912
Louisiana	19,866	13,369	110,599	69,679	130,465	83,048
New York	407	395	85,486	74,573	85,893	74,968
California	8,907	5,872	69,078	58,937	77,985	64,809
Colorado	22,944	1,309	75,347	53,438	98,291	54,747
North Dakota	3,947	1,414	58,423	40,581	62,370	41,995
Virginia	801	448	39,158	38,357	39,959	38,805
Kansas	10,697	9,357	22,525	19,215	33,222	28,572
Mississippi	27,186	15,561	44,482	11,429	71,668	26,990
Alabama	-	-	5,535	5,084	5,535	5,084
Michigan	-	-	3,881	3,774	3,881	3,774
Kentucky	-	-	1,721	1,721	1,721	1,721
Arkansas	-	-	854	152	854	152
Total United States	1,918,069	1,154,726	4,182,311	2,804,623	6,100,380	3,959,349
Canada						
Alberta	1,362,326	1,085,312	833,926	757,622	2,196,252	1,842,934
Saskatchewan	375,505	345,175	103,238	99,110	478,743	444,285
Nova Scotia	-	-	749,213	374,606	749,213	374,606
Northwest Territories	699	184	747,387	204,364	748,086	204,548
British Columbia	7,681	1,920	95,674	87,710	103,355	89,630
Manitoba	15,780	15,028	67,072	66,912	82,852	81,940
New Brunswick	219	33	-	-	219	33
Total Canada	1,762,210	1,447,652	2,596,510	1,590,324	4,358,720	3,037,976
Trinidad	41,492	36,825	305,381	261,575	346,873	298,400
United Kingdom	7,159	2,078	556,397	355,465	563,556	357,543
Total	3,728,930	2,641,281	7,640,599	5,011,987	11,369,529	7,653,268

Producing Well Summary. The following table reflects EOG's ownership in natural gas and crude oil wells located in Texas, the Gulf of Mexico, Oklahoma, New Mexico, Utah, Louisiana, Mississippi, Pennsylvania, Wyoming, and various other states in the United States, Canada, Trinidad and the United Kingdom at December 31, 2005. Gross natural gas and crude oil wells include 809 with multiple completions.

	Productive Wells	
	Gross	**Net**
Natural Gas	18,739	15,644
Crude Oil	1,751	1,201
Total	20,490	16,845

Drilling and Acquisition Activities. During the years ended December 31, 2005, 2004 and 2003, EOG expended $1,878 million, $1,510 million and $1,333 million, respectively, for exploratory and development drilling and acquisition of leases and producing properties. EOG drilled, participated in the drilling of or acquired wells as set out in the table below for the periods indicated:

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Completed						
United States and Canada						
Gas	1,523	1,241.3	1,839	1,623.3	1,586	1,440.0
Oil	79	68.6	92	79.3	89	79.0
Dry	80	70.0	104	86.9	89	78.0
Total	1,682	1,379.9	2,035	1,789.5	1,764	1,597.0
Outside United States and Canada						
Gas	2	0.6	5	4.1	-	-
Oil	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	2	0.6	5	4.1	-	-
Total Development	1,684	1,380.5	2,040	1,793.6	1,764	1,597.0
Exploratory Wells Completed						
United States and Canada						
Gas	61	47.0	49	44.2	46	28.9
Oil	3	2.6	5	3.0	5	4.2
Dry	23	17.5	41	29.2	39	29.2
Total	87	67.1	95	76.4	90	62.3
Outside United States and Canada						
Gas	-	-	1	1.0	2	0.6
Oil	-	-	-	-	-	-
Dry	3	0.7	3	1.9	2	1.5
Total	3	0.7	4	2.9	4	2.1
Total Exploratory	90	67.8	99	79.3	94	64.4
Total	1,774	1,448.3	2,139	1,872.9	1,858	1,661.4
Wells in Progress at end of period	160	123.9	63	49.4	90	79.5
Total	1,934	1,572.2	2,202	1,922.3	1,948	1,740.9
Wells Acquired(1)						
Gas	37	20.4	249	151.7	1,274	1,079.0
Oil	-	-	8	7.3	108	68.0
Total	37	20.4	257	159.0	1,382	1,147.0

(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 contract basis with independent drilling contractors. EOG owns no drilling equipment.

ITEM 3. ***Legal Proceedings***

The information required by this Item is included in this report as set forth in the Contingencies section in Note 7 of Notes to Consolidated Financial Statements on page F-24.

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 2005.

PART II

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

The following table sets forth, for the periods indicated, the high and low price per share for the common stock of EOG, as reported on the New York Stock Exchange Composite Tape, and the amount of common stock dividend declared per share.

	Price Range High	Price Range Low	Dividend Declared
2005			
First Quarter	$ 48.84	$ 32.05	$ 0.04
Second Quarter	57.94	42.40	0.04
Third Quarter	77.00	57.18	0.04
Fourth Quarter	82.00	59.96	0.04
2004(1)			
First Quarter	$ 23.73	$ 21.23	$ 0.03
Second Quarter	31.85	22.66	0.03
Third Quarter	33.44	27.60	0.03
Fourth Quarter	38.25	32.08	0.03

(1) Restated for two-for-one stock split effective March 1, 2005, as discussed below.

On February 2, 2005, EOG announced that the Board of Directors had approved a two-for-one stock split in the form of a stock dividend, payable to record holders as of February 15, 2005 and to be issued on March 1, 2005. In addition, the Board increased the quarterly cash dividend on the common stock by 33%, resulting in a quarterly cash dividend of $0.08 per share pre-split, or $0.04 per share post-split.

On February 1, 2006, the Board increased the quarterly cash dividend on the common stock from the previous $0.04 per share to $0.06 per share.

As of February 17, 2006, there were approximately 270 record holders of EOG's common stock, including individual participants in security position listings. There are an estimated 122,000 beneficial owners of EOG's common stock, including shares held in street name.

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

The following table sets forth, for the periods indicated, EOG's 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, 2005 - October 31, 2005	992	$67.84	-	6,386,200
November 1, 2005 - November 30, 2005	-	-	-	6,386,200
December 1, 2005 - December 31, 2005	-	-	-	6,386,200
Total	992	$67.84		

(1) The quarterly total number of shares of 992 consists solely of zero shares (33,079 shares for the full year 2005) that were returned to EOG in payment of the exercise price of employee stock options and 992 shares (121,969 shares for the full year 2005) that were withheld by or returned to EOG to satisfy tax withholding obligations that arose upon the exercise of employee stock options or the vesting of restricted stock or units.

(2) In September 2001, EOG announced that its Board authorized the repurchase of up to 10,000,000 shares of EOG's common stock. During 2005, EOG did not repurchase any shares under the Board authorized repurchase program.

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

Year Ended December 31	**2005**	**2004**	**2003**	**2002**	**2001**
Statement of Income Data:					
Net Operating Revenues	$ 3,620,213	$ 2,271,225	$ 1,744,675	$ 1,094,682	$ 1,655,722
Operating Income	1,991,815	979,195	697,314	180,977	675,387
Net Income Before Cumulative Effect of Change in Accounting Principle	1,259,576	624,855	437,276	87,173	398,616
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)	-	-	(7,131)	-	-
Net Income	1,259,576	624,855	430,145	87,173	398,616
Preferred Stock Dividends	7,432	10,892	11,032	11,032	10,994
Net Income Available to Common	$ 1,252,144	$ 613,693	$ 419,113	$ 76,141	$ 387,622
Net Income Per Share Available to Common(2)					
Basic					
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.24	$ 2.63	$ 1.86	$ 0.33	$ 1.67
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)	-	-	(0.03)	-	-
Net Income Per Share Available to Common	$ 5.24	$ 2.63	$ 1.83	$ 0.33	$ 1.67
Diluted					
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.13	$ 2.58	$ 1.83	$ 0.32	$ 1.65
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)	-	-	(0.03)	-	-
Net Income Per Share Available to Common	$ 5.13	$ 2.58	$ 1.80	$ 0.32	$ 1.65
Dividends Per Common Share(2)	$ 0.160	$ 0.120	$ 0.095	$ 0.080	$ 0.078
Average Number of Common Shares(2)					
Basic	238,797	233,751	229,194	230,669	231,530
Diluted	243,975	238,376	233,037	234,491	234,977

(1) EOG adopted Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003. Pro forma net income for 2000 through 2002 is not presented since the pro forma application of SFAS No. 143 to the prior periods would not result in pro forma net income materially different from the actual amount reported.
(2) Years 2001 through 2004 restated for two-for-one stock split effective March 1, 2005.

At December 31	**2005**	**2004**	**2003**	**2002**	**2001**
Balance Sheet Data:					
Net Oil and Gas Properties	$ 6,087,179	$ 5,101,603	$ 4,248,917	$ 3,321,548	$ 3,055,910
Total Assets	7,753,320	5,798,923	4,749,015	3,813,568	3,414,044
Current and Long-Term Debt	985,067	1,077,622	1,108,872	1,145,132	855,969
Shareholders' Equity	4,316,292	2,945,424	2,223,381	1,672,395	1,642,686

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

Overview

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

Net income available to common for 2005 of $1,252 million was up 104% compared to 2004 net income available to common of $614 million, attributable primarily to higher commodity prices and increased production. At December 31, 2005, EOG's total reserves were 6.2 trillion cubic feet equivalent, an increase of 548 billion cubic feet equivalent (Bcfe) from December 31, 2004.

Operations

Several important developments have occurred since January 1, 2005.

United States and Canada. The Fort Worth, Texas office was opened in 2004 to expand on EOG's drilling success in the Barnett Shale play of the Fort Worth Basin. EOG has successfully expanded the play beyond its conventional limits by using horizontal drilling and enhanced completion technology. By year-end 2005, EOG had over 500,000 acres under lease in several counties. EOG plans on substantially increasing its drilling program in 2006.

EOG's effort to identify plays with larger reserve potential has proven a successful supplement to its base development and exploitation program in the United States and Canada. EOG plans to continue to drill numerous wells in large acreage plays, which in the aggregate are expected to contribute substantially to EOG's crude oil and natural gas production. EOG has several larger potential plays under way in Wyoming, Utah, Texas, Oklahoma and western Canada.

International. During 2005, EOG commenced natural gas production in Trinidad to supply two new long-term contracts. First, EOG is supplying natural gas that is being used as feedstock for the M5000 methanol plant which commenced operations in September 2005. Second, the Atlantic LNG Train 4 (ALNG) began taking gas in December 2005, prior to commercial operations, and volumes supplied by EOG during this pre-start up period have been higher than EOG's contractual rate.

Although EOG continues to focus on United States and Canada natural gas, EOG sees an increasing linkage between United States and Canada natural gas demand and Trinidad natural gas supply. For example, liquefied natural gas (LNG) imports from existing and planned facilities in Trinidad are serious contenders to meet increasing United States demand. In addition, ammonia, methanol and chemical production has been relocating from the United States and Canada to Trinidad, driven by attractive natural gas feedstock prices in the island nation. EOG believes that its existing position with the supply contracts to the two ammonia plants, the new methanol plant and the ALNG, will continue to give its portfolio an even broader exposure to United States and Canada natural gas fundamentals.

In 2005, EOG continued its progress in the Southern Gas Basin of the United Kingdom North Sea. Production commenced in January 2005 from the Arthur 1 well and in July 2005 from the Arthur 2 well. The Arthur 3 well is expected to spud in the first half of 2006. EOG expects only modest activity in 2006 due to the difficulty in obtaining rigs in the North Sea.

Capital Structure

As noted, one of management's key strategies is to keep a strong balance sheet with a consistently below average debt-to-total capitalization ratio. At December 31, 2005, EOG's debt-to-total capitalization ratio was 19%, down from 27% at year-end 2004. By primarily utilizing cash provided from its operating activities and proceeds from stock options exercised in 2005, EOG funded its $1,858 million exploration and development expenditures, paid down $93 million of debt and paid dividends to common shareholders of $36 million. In addition, in 2006, EOG's Board of Directors increased the cash dividend on common stock to an annual rate of $0.24 per share, which represents a 50% increase in the annual cash dividend. As management currently assesses price forecast and demand trends for 2006, EOG believes that operations and capital expenditure activity can essentially be funded by cash from operations.

For 2006, EOG's estimated exploration and development expenditure budget is approximately $2.5 billion, excluding acquisitions. United States and Canada natural gas continues to be a key component of this effort. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management believes that EOG continues to maintain one of the strongest prospect inventories in EOG's history.

The following review of operations for each of the three years in the period ended December 31, 2005 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page F-1.

Results of Operations

Net Operating Revenues

During 2005, net operating revenues increased $1,349 million to $3,620 million from $2,271 million in 2004. Total wellhead revenues, which are revenues generated from sales of natural gas, crude oil, condensate and natural gas liquids, increased $1,306 million, or 57%, to $3,607 million as compared to $2,301 million in 2004. Natural gas, crude oil, condensate and natural gas liquids revenues solely represent wellhead revenues for these products. Wellhead volume and price statistics for the years ended December 31, were as follows:

	2005	2004	2003
Natural Gas Volumes (MMcfd) (1)			
United States	718	631	638
Canada	228	212	165
Trinidad	231	186	152
United Kingdom	39	7	-
Total	**1,216**	**1,036**	**955**
Average Natural Gas Prices ($/Mcf) (2)			
United States	$ 7.86	$ 5.72	$ 5.06
Canada	7.14	5.22	4.66
Trinidad	2.20 (3)	1.51	1.35
United Kingdom	6.99	5.14	-
Composite	**6.62**	**4.86**	**4.40**
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	21.5	21.1	18.5
Canada	2.4	2.7	2.3
Trinidad	4.5	3.6	2.4
United Kingdom	0.2	-	-
Total	**28.6**	**27.4**	**23.2**
Average Crude Oil and Condensate Prices ($/Bbl) (2)			
United States	$ 54.57	$ 40.73	$ 30.24
Canada	50.49	37.68	28.54
Trinidad	57.36	39.12	28.88
United Kingdom	49.62	-	-
Composite	**54.63**	**40.22**	**29.92**
Natural Gas Liquids Volumes (MBbld) (1)			
United States	6.6	4.8	3.2
Canada	0.9	0.8	0.6
Total	**7.5**	**5.6**	**3.8**
Average Natural Gas Liquids Prices ($/Bbl) (2)			
United States	$ 35.59	$ 27.79	$ 21.53
Canada	35.59	23.23	19.13
Composite	**35.59**	**27.13**	**21.13**
Natural Gas Equivalent Volumes (MMcfed) (4)			
United States	886	786	768
Canada	248	233	183
Trinidad	259	207	166
United Kingdom	40	7	-
Total	**1,433**	**1,233**	**1,117**
Total Bcfe (4) Deliveries	523.0	451.5	407.8

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Dollars per thousand cubic feet or per barrel, as applicable.
(3) Includes $0.23 per Mcf as a result of a revenue adjustment related to an amended Trinidad take-or-pay contract.
(4) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil, condensate and natural gas liquids.

2005 compared to 2004. Wellhead natural gas revenues for 2005 increased $1,097 million, or 60%, to $2,939 million from $1,842 million for 2004 due to a higher composite average wellhead natural gas price ($763 million), increased natural gas deliveries ($315 million) and a second quarter 2005 revenue adjustment related to an amended Trinidad take-or-pay contract ($19 million). The composite average wellhead natural gas price increased 36% to $6.62 per Mcf for 2005 from $4.86 per Mcf in 2004. Excluding the aforementioned adjustment, the composite average wellhead natural gas price increased 35% to $6.58 per Mcf for 2005. This adjustment increased the average Trinidad wellhead natural gas price by $0.23 per Mcf for 2005.

Natural gas deliveries increased 180 MMcfd, or 17%, to 1,216 MMcfd for 2005 from 1,036 MMcfd in 2004. The increase was due to higher production of 87 MMcfd in the United States, 45 MMcfd in Trinidad, 32 MMcfd in the United Kingdom and 16 MMcfd in Canada. The increase in the United States was primarily attributable to increased production from Texas (63 MMcfd) and Louisiana (20 MMcfd). The increase in Trinidad was due to the increased contractual requirements and demand related to the ammonia and methanol plants. The increase in the United Kingdom was due to the commencement of production from the Arthur field in January 2005 (24 MMcfd) and the full year production from the Valkyrie field, which commenced production in August 2004 (8 MMcfd). The increase in Canada was attributable to the drilling program, primarily in the Wapiti, Drumheller and Connorsville areas.

Wellhead crude oil and condensate revenues increased $168 million, or 42%, to $571 million from $403 million as compared to 2004, due to increases in both the composite average wellhead crude oil and condensate price ($151 million) and the wellhead crude oil and condensate deliveries ($17 million). The composite average wellhead crude oil and condensate price for 2005 was $54.63 per barrel compared to $40.22 per barrel for 2004.

Natural gas liquids revenues increased $42 million, or 76%, to $97 million from $55 million as compared to 2004, due to increases in the composite average price ($23 million) and deliveries ($19 million).

During 2005, EOG recognized gains on mark-to-market financial commodity derivative contracts of $10 million, which included realized gains of $10 million. During 2004, EOG recognized losses on mark-to-market financial commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million.

2004 compared to 2003. Wellhead natural gas revenues for 2004 increased $307 million, or 20%, to $1,842 million from $1,535 million for 2003 due to increases in natural gas deliveries ($134 million) and the composite average wellhead natural gas price ($173 million). The composite average wellhead natural gas price increased 10% to $4.86 per Mcf for 2004 from $4.40 per Mcf in 2003.

Natural gas deliveries increased 81 MMcfd, or 8%, to 1,036 MMcfd for 2004 from 955 MMcfd in 2003, due to a 47 MMcfd, or 28%, increase in Canada; a 34 MMcfd, or 22%, increase in Trinidad; and a 7 MMcfd increase in the United Kingdom due to commencement of production in August 2004, partially offset by a 7 MMcfd, or 1% decline in the United States. The increased deliveries in Canada (47 MMcfd) were attributable to property acquisitions completed in the fourth quarter of 2003 and additional production related to post acquisition drilling. The increase in Trinidad was attributable to the increased production from the U(a) Block (22 MMcfd) which began supplying natural gas in mid-2004 to the N2000 ammonia plant and commencement of production from the Parula wells on the SECC Block in February 2004 (12 MMcfd).

Wellhead crude oil and condensate revenues increased $149 million, or 59%, to $403 million from $254 million as compared to 2003, due to increases in both the composite average wellhead crude oil and condensate price ($103 million) and the wellhead crude oil and condensate deliveries ($46 million). The composite average wellhead crude oil and condensate price for 2004 was $40.22 per barrel compared to $29.92 per barrel for 2003.

Wellhead crude oil and condensate deliveries increased 4.2 MBbld, or 18%, to 27.4 MBbld from 23.2 MBbld for 2003. The increase was mainly due to production from new wells in the United States (2.6 MBbld) and higher production in Trinidad from the Parula wells (0.8 MBbld) and from the U(a) Block as a result of new production (0.4 MBbld).

Natural gas liquids revenues were $26 million higher than a year ago primarily due to increases in deliveries ($14 million) and the composite average price ($12 million).

During 2004, EOG recognized losses on mark-to-market commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million. During 2003, EOG recognized losses on mark-to-market commodity derivative contracts of $80 million, which included realized losses of $45 million and collar premium payments of $3 million.

Operating and Other Expenses

2005 compared to 2004. During 2005, operating expenses of $1,628 million were $336 million higher than the $1,292 million incurred in 2004. The following table presents the costs per Mcfe for the years ended December 31:

	2005	2004
Lease and Well, including Transportation	$0.71	$0.60
Depreciation, Depletion and Amortization (DD&A)	1.25	1.12
General and Administrative (G&A)	0.24	0.25
Taxes Other Than Income	0.38	0.30
Interest Expense, Net	0.12	0.14
Total Per-Unit Costs [(1)]	**$2.70**	**$2.41**

(1) Total per-unit costs do not include exploration costs, dry hole costs and impairments.

The per-unit costs of lease and well, including transportation, DD&A, taxes other than income and interest expense, net for 2005 compared to 2004 were due primarily to the reasons set forth below.

Lease and well expense includes expenses for EOG operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expense can be divided into the following categories: costs to operate and maintain EOG's oil and natural gas wells, the cost of workovers, transportation costs associated with selling hydrocarbon products and lease and well administrative expenses. Operating and maintenance expenses include, among other service costs, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep, fuel and power. Workovers are costs 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, including transportation, of $373 million were $102 million higher than 2004 due primarily to higher operating and maintenance expenses in the United States ($40 million); increased transportation related costs in the United States ($28 million) and the United Kingdom ($7 million); higher lease and well administrative expenses in the United States ($11 million); changes in the Canadian exchange rate ($6 million); and higher workover expenditures in the United States ($3 million) and Trinidad ($2 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 an individual field, such as the field production profile; drilling or acquisition of new wells; disposition of existing wells; reserve revisions (upward or downward), primarily related to well performance; and impairments. Changes to the individual fields, due to any of these factors, may cause EOG's composite DD&A rate and expense to fluctuate from year to year.

DD&A expenses of $654 million were $150 million higher than 2004 primarily as a result of increased production in the United States ($46 million), Canada ($6 million) and Trinidad ($5 million) and the commencement of production in the United Kingdom ($14 million). DD&A rates increased in the United States due to a gradual proportional increase in production from higher cost properties ($59 million) and in Canada predominantly from the development of acquired proved reserves ($9 million). The Canadian exchange rate also contributed to the DD&A expense increase ($8 million).

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Taxes other than income of $199 million were $65 million higher than 2004.

Severance/production taxes increased due primarily to increased wellhead revenues in the United States ($41 million), Trinidad ($7 million) and Canada ($3 million), partially offset by the increase in credits taken for a Texas high cost gas severance tax exemption ($10 million) and a production tax audit lawsuit in the first quarter of 2004 ($5 million). Other items contributing to the increase were an additional Trinidadian Supplemental Petroleum Tax expense as a result of 2005 tax legislation that increased the tax expense retroactively to January 2004 ($7 million) and 2004 production tax relief in Trinidad ($6 million). Ad valorem/property taxes increased primarily due to higher property valuation in the United States ($11 million).

Net interest expense in 2005 included costs associated with the early retirement of 2008 Notes ($8 million) (see Note 2 to Consolidated Financial Statements). Excluding these early retirement costs, the 2005 net interest expense decreased $8 million compared to 2004 primarily due to higher capitalized interest ($5 million), an interest charge related to the results of a production tax audit lawsuit in the first quarter of 2004 ($2 million) and lower average debt balance in the United States ($1 million).

Exploration costs of $133 million were $39 million higher than 2004 due primarily to increased geological and geophysical expenditures in the Barnett Shale area.

Impairments include amortization of unproved leases, as well as impairments under the Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which requires an entity to compute impairments to the carrying value of long-lived assets based on future cash flow analysis. Impairments of $78 million were $4 million lower than 2004 due primarily to lower amortization of unproved leases in the United States ($12 million) and lower impairments to the carrying value of certain long-lived assets in Canada ($8 million), partially offset by higher impairments to the carrying value of certain long-lived assets in the United States ($14 million) and higher amortization of unproved leases in Canada ($2 million). EOG recorded impairments of $31 million and $25 million for 2005 and 2004, respectively, under SFAS No. 144 for certain properties in the United States and Canada.

Other income, net of $36 million increased $26 million compared to 2004 primarily as a result of higher gains on sales of properties ($7 million), interest income ($6 million) and equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants in 2005 ($5 million); decreased net foreign currency transaction losses ($4 million); and a gain on the sale of part of EOG’s interest in the N2000 ammonia plant in the first quarter of 2005 ($2 million).

Income tax provision of $706 million increased $404 million as compared to 2004, due primarily to higher pre-tax income ($383 million) and income taxes associated with the repatriation of foreign earnings ($24 million). The effective tax rate for 2005 increased to 36% from 33% in 2004.

2004 compared to 2003. During 2004, operating expenses of $1,292 million were $245 million higher than the $1,047 million incurred in 2003. The following table presents the costs per Mcfe for the years ended December 31:

	2004	**2003**
Lease and Well, including Transportation	$0.60	$0.52
DD&A	1.12	1.08
G&A	0.25	0.25
Taxes Other Than Income	0.30	0.21
Interest Expense, Net	0.14	0.14
Total Per-Unit Costs	**$2.41**	**$2.20**

The higher per-unit costs of lease and well, including transportation, DD&A and taxes other than income for 2004 compared to 2003 were due primarily to the reasons set forth below.

Lease and well expenses, including transportation, of $271 million were $58 million higher than 2003 due primarily to a general increase in service costs related to increased operating activities, including an increase in the number of wells, in the United States ($18 million), Canada ($16 million), and Trinidad ($1 million); increased transportation related costs in the United States ($14 million), Canada ($2 million) and the United Kingdom ($2 million); and changes in the Canadian exchange rate ($5 million).

DD&A expenses of $504 million increased $63 million from 2003 due primarily to increased production in Canada ($18 million), the United States ($10 million), and Trinidad ($4 million); the commencement of production in the United Kingdom ($2 million); increased DD&A rates in the United States due to a gradual proportional increase in production from higher cost properties ($13 million); increased DD&A rates in Canada mainly from developing acquired proved reserves ($8 million); and changes in the Canadian exchange rate ($7 million).

G&A expenses of $115 million were $15 million higher than 2003 due primarily to expanded operations.

Taxes other than income of $134 million were $48 million higher than 2003 due primarily to a decrease in credits taken against severance taxes resulting from the qualification of additional wells for a Texas high cost gas severance tax exemption ($19 million); an increase as a result of higher wellhead revenues in the United States ($13 million), Trinidad ($2 million) and Canada ($1 million); higher property taxes as a result of higher property valuation in the United States ($6 million); the results of a production tax audit lawsuit in the first quarter of 2004 ($5 million); and an increase in the number of wells and facilities in Canada ($2 million).

Exploration costs of $94 million were $18 million higher than 2003 due primarily to increased geological and geophysical expenditures in the United States ($6 million), Canada ($3 million), the United Kingdom ($3 million) and Trinidad ($1 million); and increased exploration administrative expenses across EOG ($4 million).

Impairments of $82 million were $8 million lower than 2003 due primarily to lower amortization of unproved leases in the United States ($10 million), partially offset by higher amortization of unproved leases in Canada ($2 million). Total impairments under SFAS No. 144 were $25 million in each of 2004 and 2003.

Net interest expense of $63 million was $4 million higher than 2003 due primarily to a slightly higher average debt balance.

Other income (expense), net for 2004 included income from equity investments of $11 million, gains on sales of reserves and related assets of $6 million and foreign currency transaction losses of $7 million as a result of applying the changes in the Canadian exchange rate to certain intercompany short-term loans that eliminate in consolidation.

Income tax provision increased $85 million to $301 million compared to 2003, primarily resulting from higher income before income taxes ($95 million), offset by lower deferred income taxes associated with the Alberta, Canada corporate tax rate ($5 million) and lower effective foreign income tax rates ($2 million). The net effective tax rate for 2004 remained unchanged from the 2003 rate of 33%.

In November 2003, Canada enacted legislation reducing the Canadian federal income tax rate for companies in the resource sector from 28% to 27% for 2003, with further reductions to 21% phased in over the next four years. This legislation also made changes to the tax treatment of crown royalties and the resource allowance. Beginning in 2003, Canadian taxpayers are allowed to deduct 10% of actual provincial and other crown royalties. This percentage increases each year through 2007, at which time 100% of crown royalties will be deductible. The resource allowance, a statutory deduction calculated as 25% of adjusted resource profits, will be phased out through 2007, when the deduction will be completely eliminated.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2005 included funds generated from operations, funds from new borrowings, proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan, proceeds from the sale of oil and gas properties and proceeds from sales of partial interests in certain equity investments in Trinidad. Primary cash outflows included funds used in operations, exploration and development expenditures, oil and gas property acquisitions, repayment of debt, dividend payments to shareholders, redemption of preferred stock and common stock repurchases.

2005 compared to 2004. Net cash provided by operating activities of $2,369 million in 2005 increased $925 million as compared to 2004 primarily reflecting an increase in wellhead revenues ($1,306 million), a favorable change in the net cash flows from settlement of financial commodity derivative contracts ($93 million) and favorable changes in working capital and other liabilities ($35 million), partially offset by an increase in cash operating expenses ($217 million) and an increase in cash paid for income taxes ($279 million).

Net cash used in investing activities of $1,678 million in 2005 increased by $281 million as compared to 2004 due primarily to increased additions to oil and gas properties ($308 million) and unfavorable changes in working capital related to investing activities ($28 million), partially offset by an increase in proceeds from the sale of oil and gas properties in 2005 ($40 million) and the sale of part of EOG's interest in the N2000 ammonia plant in 2005 ($18 million). Changes in Components of Working Capital Associated with Investing Activities included changes in accounts payable associated with the accrual of exploration and development expenditures and changes in inventories which represent material and equipment used in drilling and related activities.

Cash used in financing activities of $72 million in 2005 increased $29 million as compared to 2004. Cash provided by financing activities for 2005 included a long-term debt borrowing ($250 million) and proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan ($65 million). Cash used by financing activities for 2005 included repayments of long-term debt borrowings ($343 million) and cash dividend payments ($43 million).

2004 compared to 2003. Net cash provided by operating activities of $1,444 million in 2004 increased $195 million as compared to 2003 primarily reflecting an increase in wellhead revenues of $482 million, partially offset by an increase in cash operating expenses of $139 million, an increase in current tax expense of $72 million, unfavorable changes in working capital and other liabilities of $48 million and an increase in realized losses from mark-to-market commodity derivative contracts of $38 million.

Net cash used in investing activities of $1,397 million in 2004 increased by $189 million as compared to 2003 due primarily to increased additions to oil and gas properties of $171 million and unfavorable changes in working capital related to investing activities of $12 million. Changes in Components of Working Capital Associated with Investing Activities included changes in accounts payable associated with the accrual of exploration and development expenditures and changes in inventories which represent material and equipment used in drilling and related activities.

Cash used in financing activities was $43 million in 2004 versus $57 million in 2003. Cash provided by financing activities for 2004 included long-term debt borrowing of $150 million and proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan of $76 million. Cash used by financing activities for 2004 included repayments of long-term debt borrowings of $175 million, redemption of all 500 outstanding shares of Series D Preferred Stock of $50 million and cash dividend payments of $38 million.

Total Exploration and Development Expenditures

The table below sets out components of total exploration and development expenditures for the years ended December 31, 2005, 2004 and 2003, along with the total budgeted for 2006, excluding acquisitions (in millions):

	Actual				Budgeted 2006
	2005	**2004**	**2003**		**(excluding acquisitions)**
Expenditure Category					
Capital					
Drilling and Facilities	$ 1,458	$ 1,120	$ 731		
Leasehold Acquisitions	131	143	59		
Producing Property Acquisitions	56	52	405		
Capitalized Interest	15	10	9		
Subtotal	1,660	1,325	1,204		
Exploration Costs	133	94	76		
Dry Hole Costs	65	92	41		
Exploration and Development Expenditures	1,858	1,511	1,321		Approximately $2,500
Asset Retirement Costs	20	16	12	(1)	
Deferred Income Tax on Acquired Properties	-	(17)	-		
Total Exploration and Development Expenditures	**$ 1,878**	**$ 1,510**	**$ 1,333**		

(1) Asset Retirement Costs for 2003 does not include the cumulative effect of adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003.

Exploration and development expenditures of $1,858 million for 2005 were $347 million higher than the prior year due primarily to (i) increased drilling and facilities expenditures of $338 million resulting from higher drilling and facilities expenditures in the United States ($377 million) and changes in the Canadian exchange rate related to drilling and facilities expenditures ($17 million), partially offset by decreased drilling and facilities expenditures in the United Kingdom ($24 million), Trinidad ($21 million) and Canada ($11 million) and; (ii) increased exploration costs ($39 million) primarily in the Barnett Shale area; partially offset by decreased dry hole costs ($27 million). The 2005 exploration and development expenditures of $1,858 million includes $1,300 million in development, $487 million in exploration, $56 million in property acquisitions and $15 million in capitalized interest. The 2004 exploration and development expenditures of $1,511 million includes $1,009 million in development, $440 million in exploration, $52 million in property acquisitions and $10 million in capitalized interest. The 2003 exploration and development expenditures of $1,321 million included $651 million in development, $256 million in exploration, $405 million in property acquisitions and $9 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. There are no material continuing commitments associated with current expenditure plans.

Derivative Transactions

During 2005, EOG recognized gains on mark-to-market financial commodity derivative contracts of $10 million, which included realized gains of $10 million. During 2004, EOG recognized losses on mark-to-market financial commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million. (See Note 11 to Consolidated Financial Statements.)

Presented below is a summary of EOG's 2006 natural gas financial collar and price swap contracts at February 22, 2006, with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units per day (MMBtud). As indicated, EOG does not have any financial collar or price swap contracts that cover periods beyond October 2006. As of February 22, 2006, EOG had no crude oil hedges. EOG accounts for these collar and price swap contracts using mark-to-market accounting.

Natural Gas Financial Contracts

	Collar Contracts					Price Swap Contracts	
		Floor Price		Ceiling Price			
Month	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
February (closed)	50,000	$13.65 - 14.50	$14.05	$16.20 - 17.04	$16.59	-	-
March	50,000	13.50 - 14.30	13.87	15.95 - 17.05	16.46	170,000	$9.54
April	50,000	10.00 - 10.50	10.23	12.60 - 13.00	12.77	180,000	9.49
May	50,000	9.75 - 10.00	9.87	12.15 - 12.60	12.31	180,000	9.50
June	50,000	9.75 - 10.00	9.87	12.20 - 12.60	12.34	180,000	9.54
July	50,000	9.75 - 10.00	9.87	12.35 - 12.85	12.50	190,000	9.57
August	50,000	9.75 - 10.00	9.87	12.50 - 13.00	12.67	190,000	9.63
September	-	-	-	-	-	140,000	9.40
October	-	-	-	-	-	90,000	9.46

Financing

EOG's debt-to-total capitalization ratio was 19% as of December 31, 2005 compared to 27% as of December 31, 2004.

During 2005, total debt decreased $93 million to $985 million (see Note 2 to Consolidated Financial Statements). The estimated fair value of EOG's debt at December 31, 2005 and 2004 was $1,025 million and $1,146 million, respectively. The estimated fair value was based upon quoted market prices and, where such prices were not available, upon interest rates currently available to EOG at year-end. EOG's debt is primarily at fixed interest rates. At December 31, 2005, a 1% decline in interest rates would result in a $46 million increase in the estimated fair value of the fixed rate obligations (see Note 11 to Consolidated Financial Statements).

During 2005 and 2004, EOG utilized cash provided by operating activities and commercial paper to fund its operations. While EOG maintains a $600 million commercial paper program, the maximum outstanding at any time during 2005 was $380 million, and the amount outstanding at year-end was zero. EOG considers this excess availability, which is backed by the $600 million Revolving Credit Agreement with domestic and foreign lenders described in Note 2 to Consolidated Financial Statements, combined with approximately $688 million of availability under its shelf registration described below, to be ample to meet its ongoing operating needs.

In 2005, the short-term commercial paper loan balance was reduced by $92 million; the $174 million, 6.00% Notes due 2008 and the remaining $75 million outstanding under the Senior Unsecured Term Loan Facility were repaid primarily with cash generated from operating activities. On February 17, 2006, a foreign subsidiary of EOG repaid $50 million of the $250 million it borrowed in 2005 (see Note 2 to Consolidated Financial Statements). During 2006, based on resources available at December 31, 2005, EOG plans to pay off the $126 million, 6.70% Notes due 2006.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2005 (in thousands):

Contractual Obligations (1)	Total	2006	2007 - 2009	2010 - 2011	2012 & Beyond
Current and Long-Term Debt	$ 985,067	$ 126,075	$ 348,992	$ 220,000	$ 290,000
Non-cancelable Operating Leases	84,536	40,440	26,934	8,073	9,089
Interest Payments on Current and Long-Term Debt	420,466	58,944	126,424	63,670	171,428
Pipeline Transportation Service Commitments (2)	273,185	40,752	93,065	59,081	80,287
Drilling Rig Commitments	182,955	75,624	107,331	-	-
Seismic Purchase Obligations	3,479	3,479	-	-	-
Other Purchase Obligations	7,072	5,837	1,235	-	-
Total Contractual Obligations	**$ 1,956,760**	**$ 351,151**	**$ 703,981**	**$ 350,824**	**$ 550,804**

(1) This table does not include the liability for dismantlement, abandonment and restoration costs of oil and gas properties. Effective with adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003, EOG recorded a separate liability for the fair value of this asset retirement obligation (see Note 13 to Consolidated Financial Statements). In addition, this table does not include EOG's pension or postretirement benefit obligations (see Note 6 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, 2005. 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.

Shelf Registration

As of February 22, 2006, the amount available under various filed registration statements with the Securities and Exchange Commission for the offer and sale from time to time of EOG debt securities, preferred stock and/or common stock totaled approximately $688 million.

Off-Balance Sheet Arrangements

EOG does not participate in financial transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities, 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 contractually narrow or limited purposes. EOG was not involved in any unconsolidated VIE or SPE financial transactions during any of the reporting periods in this document and has no intention to participate in such transactions in the foreseeable future.

Foreign Currency Exchange Rate Risk

During 2005, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Canada, Trinidad and the United Kingdom. The foreign currency most significant to EOG's operations during 2005 was the Canadian Dollar. The continued strengthening of the Canadian Dollar in 2005 impacted both the revenues and expenses of EOG's Canadian subsidiaries. However, since the Canadian natural gas 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 any exchange rate impacts that may result from the notes offered by one of the 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 SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149. Under those provisions, as of December 31, 2005, EOG recorded the fair value of the swap of $36 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 on the Consolidated Statements of Income and Comprehensive Income. The after-tax net impact from the foreign currency swap transaction resulted in a negative change of $5 million for the year ended December 31, 2005. This amount is included in Accumulated Other Comprehensive Income in the Shareholders' Equity section of the Consolidated Balance Sheets.

Outlook

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. In EOG's opinion, overall natural gas production in the United States is declining. In addition, the increasing recognition of natural gas as a more environmentally friendly source of energy is likely to result in increases in demand. 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 prices. Longer term natural gas prices will be determined by the supply and demand for natural gas as well as the prices of competing fuels, such as oil and coal.

Assuming a totally unhedged position for 2006, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2006 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf change in average wellhead natural gas price is approximately $24 million for net income and operating cash flow. EOG is not impacted as significantly by changing crude oil price. EOG's price sensitivity in 2006 for each $1.00 per barrel change in average wellhead crude oil prices is approximately $6 million for net income and operating cash flow. For information regarding EOG's natural gas hedge position as of December 31, 2005, see Note 11 to Consolidated Financial Statements.

Marketing companies have played an important role in the United States and Canada natural gas market. These companies aggregate natural gas supplies through purchases from producers like EOG and then resell the gas to end users, local distribution companies or other buyers. In recent years, several of the largest natural gas marketing companies have filed for bankruptcy or are having financial difficulty, and others are exiting this business. EOG does not believe that this will have a material effect on its ability to market its natural gas production. EOG continues to assess and monitor the creditworthiness of partners to whom it sells its production and where appropriate, to seek new markets.

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. However, in order to diversify its overall asset portfolio and as a result of its overall success realized in Trinidad and the United Kingdom North Sea, EOG anticipates expending a portion of its available funds in the further development of opportunities outside the United States and Canada. In addition, 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 other exploitation type opportunities. Budgeted 2006 exploration and development expenditures, excluding acquisitions, are approximately $2.5 billion and are structured to maintain the flexibility necessary under EOG's strategy of funding the United States and Canada exploration, exploitation, development and acquisition activities primarily from available internally generated cash flow.

The level of exploration and development expenditures may vary in 2006 and will vary in future periods depending on energy market conditions and other related economic factors. Based upon existing economic and market conditions, EOG believes net operating cash flow and available financing alternatives in 2006 will be sufficient to fund its net investing cash requirements for the year. However, EOG has significant flexibility with respect to its financing alternatives and adjustment of its exploration, exploitation, development and acquisition expenditure plans if circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to operations in the United States, Canada, Trinidad and the United Kingdom, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Environmental Regulations

Various federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to 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 and 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. Under environmental 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 responsible under environmental laws and regulations for oil and gas properties in which EOG owns an interest but is not the operator. Compliance with such laws and regulations increases EOG's overall cost of business, but has not had a material adverse effect on EOG's operations or financial condition. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts that are material in relation to its total exploration and development expenditure program in order to comply with environmental laws and regulations but, inasmuch as such laws and regulations are frequently changed, EOG is unable to predict the ultimate cost of compliance. 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.

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, 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

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. All other exploratory wells that do not meet these criteria are expensed after one year. As of December 31, 2005 and 2004, EOG had exploratory drilling costs related to two 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.

Impairments

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are assessed quarterly on a property-by-property basis, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. 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 an asset may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

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 depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. 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 are depreciated on a straight-line basis.

Assets are grouped in accordance with paragraph 30 of SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." 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.

Stock Options

EOG accounted for stock options under the provisions and related interpretations of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." No compensation expense was recognized for such options. As allowed by SFAS No. 123, "Accounting for Stock-Based Compensation" issued in 1995, EOG continued to apply APB Opinion No. 25 for purposes of determining net income and to present the pro forma disclosures required by SFAS No. 123.

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), "Share-Based Payment," which supersedes SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FASB Statement No. 123." SFAS No. 123(R) establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This eliminates the exception to account for such awards using the intrinsic method previously allowable under APB Opinion No. 25. SFAS No. 123(R) is effective for annual reporting periods beginning on or after June 15, 2005. EOG adopted SFAS No. 123(R) effective January 1, 2006 using the modified prospective method. EOG expects this will reduce 2006 net earnings by a pre-tax amount of approximately $25 million, taking into consideration the estimated forfeitures and cancellations. This amount includes approximately $21 million of expense for unvested options outstanding at December 31, 2005 and approximately $1 million of expense for the Employee Stock Purchase Plan. SFAS No. 123(R) also requires a public entity to present its cash flows provided by tax benefits from stock options exercised in the Financing Cash Flows section of the Statement of Cash Flows. Had SFAS No. 123(R) been in effect, EOG's Net Cash Provided by Operating Activities would have been reduced and its Net Cash Provided by Financing Activities would have been increased on its Consolidated Statements of Cash Flows by $51 million, $29 million and $12 million for 2005, 2004 and 2003, respectively.

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

ITEM 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

EOG's exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk is discussed in the Derivative Transactions, Financing, Foreign Currency Exchange Rate Risk and Outlook sections of "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

ITEM 8. ***Financial Statements and Supplementary Data***

Information required hereunder is included in this report as set forth in the "Index to Financial Statements" on page F-1.

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 the end of the period covered by this report (Evaluation Date). Based on this evaluation, the principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of the Evaluation Date to ensure that information that is required to be disclosed by EOG in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the 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 Report on Internal Control over Financial Reporting. EOG's management is responsible for establishing and maintaining effective internal control over financial reporting (as defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Exchange Act). Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2005. 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, management believes that, as of December 31, 2005, EOG's internal control over financial reporting is effective based on those criteria. EOG's assessment also appears on page F-2.

EOG's independent registered public accounting firm has issued an audit report on EOG's assessment of its internal control over financial reporting. This report begins on page F-3.

There were no changes in EOG's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2005 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 and Executive Officers of the Registrant*

Directors and Executive Officers of the Registrant. The information required by this Item regarding directors is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2005, under the caption entitled "Election of Directors" of Item 1.

Audit Committee Related Matters and Code of Ethics for the CEO and CFO. The information required by this Item regarding audit committee related matters is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2005, under the caption entitled "Board of Directors and Committees" of Item 1.

ITEM 11. *Executive Compensation*

The information required by this Item is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2005, under the caption "Compensation of Directors and Executive Officers" of Item 1.

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 the Proxy Statement to be filed within 120 days after December 31, 2005, under the captions "Election of Directors" and "Compensation of Directors and Executive Officers" of Item 1.

Equity Compensation Plan Information

EOG has various plans under which employees and nonemployee members of the Board of Directors of EOG and its subsidiaries have been or may be granted certain equity compensation consisting of stock options, restricted stock, restricted stock units and phantom stock. The 1992 Stock Plan, the 1993 Nonemployee Directors Stock Option Plan, and the Employee Stock Purchase Plan have been approved by security holders. Plans that have not been approved by security holders are described below. The following table sets forth data for EOG's equity compensation plans aggregated by the various plans approved by security holders and those plans not approved by security holders as of December 31, 2005.

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 Security Holders	7,080,120	$34.01	5,527,867 (1) (2)
Equity Compensation Plans Not Approved by Security Holders	5,217,234	$19.04 (3)	118,459 (4) (5)
Total	**12,297,354**	**$27.70 (3)**	**5,646,326**

(1) Of these securities, 407,402 shares remain available for purchase under the Employee Stock Purchase Plan.
(2) Of these securities, 1,781,229 could be issued as restricted stock or restricted stock units under the 1992 Stock Plan.
(3) Weighted-average exercise price does not include 55,932 phantom stock units in the 1996 Deferral Plan which are included in column (a).
(4) Of these securities, 40,217 phantom stock units remain available for issuance under the 1996 Deferral Plan.
(5) Of these securities, 78,242 could be issued as restricted stock or restricted stock units under the 1994 Stock Plan.

Stock Plan Not Approved by Security Holders. The Board of Directors of EOG 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 plan, employees have been or may be granted stock options (rights to purchase shares of EOG common stock at a price not less than the market price of the stock at the date of grant). Stock options vest either immediately at the date of grant or 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 plan have not exceeded a maximum term of 10 years. Employees have also been or may be granted shares of restricted stock and/or restricted stock units without cost to the employee. The shares and units granted vest to the employee at various times ranging from one to five years as defined in individual grant agreements. Upon vesting, restricted shares are released to the employee. Upon vesting, each restricted stock unit is converted into one share of EOG common stock and released to the employee.

Deferral Plan Phantom Stock Account. The Board of Directors of EOG approved the 1996 Deferral Plan, under which payment of base salary, annual bonus and directors fees may be deferred into a phantom stock account. In the phantom stock account, deferrals are treated as if they had purchased shares of EOG common stock 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. A total of 120,000 shares have been registered for issuance under the plan. As of December 31, 2005, 79,783 phantom stock units had been issued and 40,217 units remained available for issuance under the plan.

ITEM 13. *Certain Relationships and Related Transactions*

None.

ITEM 14. *Principal Accounting Fees and Services*

Information regarding auditor fees, audit-related fees, tax fees and all other fees and services billed by the principal accountant is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2005, under the caption "Ratification of Appointment of Auditors - General" of Item 2.

PART IV

ITEM 15. *Exhibits and 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) Exhibits

See pages E-1 through E-4 for a listing of the exhibits.

INDEX TO FINANCIAL STATEMENTS
EOG RESOURCES, INC.

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. and its subsidiaries (EOG) were prepared by management, which is responsible for their integrity, objectivity and fair presentation. 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 effective 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 and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions.

The adequacy of financial controls of EOG and the accounting principles employed in financial reporting by EOG 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. The 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, 2005. 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, management believes that, as of December 31, 2005, EOG's internal control over financial reporting is effective based on those criteria.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements and management's assessment of the effectiveness of EOG's internal control over financial reporting, 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 shareholders, 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 the system of internal controls to the extent considered necessary to determine the audit procedures required to support their opinion on the consolidated financial statements, management's assessment of EOG's internal control over financial reporting and the effectiveness of EOG's internal control over financial reporting. Their report begins on page F-3.

MARK G. PAPA	EDMUND P. SEGNER, III	TIMOTHY K. DRIGGERS
Chairman of the Board and Chief Executive Officer	*President and Chief of Staff*	*Vice President and Chief Accounting Officer*

Houston, Texas
February 22, 2006

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, 2005 and 2004, and the related consolidated statements of income and comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited management's assessment, included in the accompanying Management's Responsibility for Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on these financial statements and financial statement schedule, an opinion on management's assessment, and an opinion on the effectiveness of 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 audit of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and 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 accounting principles generally accepted in the United States of America. 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 accounting principles generally accepted in the United States of America 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 Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, 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 13 to the consolidated financial statements, on January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

DELOITTE & TOUCHE LLP

Houston, Texas
February 22, 2006

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

Year Ended December 31	2005	2004	2003
Net Operating Revenues			
Natural Gas	$ 2,938,917	$ 1,842,316	$ 1,535,204
Crude Oil, Condensate and Natural Gas Liquids	668,073	458,446	283,042
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	10,475	(33,449)	(80,414)
Other, Net	2,748	3,912	6,843
Total	3,620,213	2,271,225	1,744,675
Operating Expenses			
Lease and Well, including Transportation	373,355	271,086	212,601
Exploration Costs	133,116	93,941	76,358
Dry Hole Costs	64,812	92,142	41,156
Impairments	77,932	81,530	89,133
Depreciation, Depletion and Amortization	654,258	504,403	441,843
General and Administrative	125,918	115,013	100,403
Taxes Other Than Income	199,007	133,915	85,867
Total	1,628,398	1,292,030	1,047,361
Operating Income	1,991,815	979,195	697,314
Other Income, Net	35,828	9,945	15,273
Income Before Interest Expense and Income Taxes	2,027,643	989,140	712,587
Interest Expense			
Incurred	77,102	72,759	67,252
Capitalized	(14,596)	(9,631)	(8,541)
Net Interest Expense	62,506	63,128	58,711
Income Before Income Taxes	1,965,137	926,012	653,876
Income Tax Provision	705,561	301,157	216,600
Net Income Before Cumulative Effect of Change in Accounting Principle	1,259,576	624,855	437,276
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	-	(7,131)
Net Income	1,259,576	624,855	430,145
Preferred Stock Dividends	7,432	10,892	11,032
Net Income Available to Common	**$ 1,252,144**	**$ 613,963**	**$ 419,113**
Net Income Per Share Available to Common			
Basic			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.24	$ 2.63	$ 1.86
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	-	(0.03)
Net Income Available to Common	$ 5.24	$ 2.63	$ 1.83
Diluted			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.13	$ 2.58	$ 1.83
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	-	(0.03)
Net Income Available to Common	$ 5.13	$ 2.58	$ 1.80
Average Number of Common Shares			
Basic	238,797	233,751	229,194
Diluted	243,975	238,376	233,037
Comprehensive Income			
Net Income	$ 1,259,576	$ 624,855	$ 430,145
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	34,074	77,925	123,811
Foreign Currency Swap Transaction	(7,567)	(5,816)	-
Income Tax Related to Foreign Currency Swap Transaction	2,615	1,972	-
Comprehensive Income	**$ 1,288,698**	**$ 698,936**	**$ 553,956**

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	2005	2004
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 643,811	$ 20,980
Accounts Receivable, Net	762,207	447,742
Inventories	63,215	40,037
Assets from Price Risk Management Activities	11,415	10,747
Deferred Income Taxes	24,376	22,227
Other	58,214	45,070
Total	1,563,238	586,803
Oil and Gas Properties (Successful Efforts Method)	11,173,389	9,599,276
Less: Accumulated Depreciation, Depletion and Amortization	(5,086,210)	(4,497,673)
Net Oil and Gas Properties	6,087,179	5,101,603
Other Assets	102,903	110,517
Total Assets	**$ 7,753,320**	**$ 5,798,923**

	2005	2004
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 679,548	$ 424,581
Accrued Taxes Payable	140,902	51,116
Dividends Payable	9,912	7,394
Deferred Income Taxes	164,659	103,933
Current Portion of Long-Term Debt	126,075	-
Other	50,945	45,180
Total	1,172,041	632,204
Long-Term Debt	858,992	1,077,622
Other Liabilities	283,407	241,319
Deferred Income Taxes	1,122,588	902,354
Shareholders' Equity		
Preferred Stock, $.01 Par, 10,000,000 Shares Authorized:		
Series B, 100,000 Shares Issued, Cumulative,		
$100,000,000 Liquidation Preference	99,062	98,826
Common Stock, $.01 Par, 640,000,000 Shares Authorized and		
249,460,000 Shares Issued	202,495	201,247
Additional Paid in Capital	84,705	21,047
Unearned Compensation	(36,246)	(29,861)
Accumulated Other Comprehensive Income	177,137	148,015
Retained Earnings	3,920,483	2,706,845
Common Stock Held in Treasury, 7,385,862 Shares at December 31,		
2005 and 11,605,112 Shares at December 31, 2004	(131,344)	(200,695)
Total Shareholders' Equity	4,316,292	2,945,424
Total Liabilities and Shareholders' Equity	**$ 7,753,320**	**$ 5,798,923**

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

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

	Preferred Stock	Common Stock	Additional Paid In Capital	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Shareholders' Equity
Balance at December 31, 2002	$147,999	$201,247	$ -	$(15,033)	$(49,877)	$1,723,948	$(335,889)	$1,672,395
Net Income	-	-	-	-	-	430,145	-	430,145
Amortization of Preferred Stock Discount	417	-	-	-	-	(417)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,615)	-	(10,615)
Common Stock Dividends Declared, $0.10 Per Share	-	-	-	-	-	(21,847)	-	(21,847)
Translation Adjustment	-	-	-	-	123,811	-	-	123,811
Treasury Stock Purchased	-	-	-	-	-	-	(25,208)	(25,208)
Treasury Stock Issued Under:								
Stock Option Plans	-	-	(16,522)	-	-	-	50,292	33,770
Employee Stock Purchase Plan	-	-	84	-	-	-	2,515	2,599
Tax Benefits from Stock Options Exercised	-	-	11,926	-	-	-	-	11,926
Restricted Stock and Units	-	-	6,084	(14,467)	-	-	8,383	-
Amortization of Unearned Compensation	-	-	-	6,027	-	-	-	6,027
Treasury Stock Issued as Compensation	-	-	53	-	-	-	325	378
Balance at December 31, 2003	148,416	201,247	1,625	(23,473)	73,934	2,121,214	(299,582)	2,223,381
Net Income	-	-	-	-	-	624,855	-	624,855
Redemption of Preferred Stock, $100,000 Per Share	(50,000)	-	-	-	-	-	-	(50,000)
Amortization of Preferred Stock Discount	410	-	-	-	-	(410)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,482)	-	(10,482)
Common Stock Dividends Declared, $0.12 Per Share	-	-	-	-	-	(28,332)	-	(28,332)
Translation Adjustment	-	-	-	-	77,925	-	-	77,925
Treasury Stock Purchased	-	-	-	-	-	-	(9,565)	(9,565)
Foreign Currency Swap Transaction Net of Income Tax Benefit of $1,972	-	-	-	-	(3,844)	-	-	(3,844)
Treasury Stock Issued Under:								
Stock Option Plans	-	-	(21,570)	-	-	-	101,077	79,507
Employee Stock Purchase Plan	-	-	694	-	-	-	2,326	3,020
Tax Benefits from Stock Options Exercised	-	-	29,396	-	-	-	-	29,396
Restricted Stock and Units	-	-	10,902	(15,951)	-	-	5,049	-
Amortization of Unearned Compensation	-	-	-	9,563	-	-	-	9,563
Balance at December 31, 2004	98,826	201,247	21,047	(29,861)	148,015	2,706,845	(200,695)	2,945,424
Net Income	-	-	-	-	-	1,259,576	-	1,259,576
Common Stock Issued - Stock Split	-	1,248	(1,248)	-	-	-	-	-
Amortization of Preferred Stock Discount	236	-	-	-	-	(236)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(7,196)	-	(7,196)
Common Stock Dividends Declared, $0.16 Per Share	-	-	-	-	-	(38,506)	-	(38,506)
Translation Adjustment	-	-	-	-	34,074	-	-	34,074
Foreign Currency Swap Transaction	-	-	-	-	(7,567)	-	-	(7,567)
Income Tax Related to Foreign Currency Swap Transaction	-	-	-	-	2,615	-	-	2,615
Treasury Stock Purchased	-	-	-	-	-	-	-	-
Treasury Stock Issued Under:								
Stock Option Plans	-	-	130	-	-	-	59,347	59,477
Employee Stock Purchase Plan	-	-	2,027	-	-	-	1,862	3,889
Tax Benefits from Stock Options Exercised	-	-	50,880	-	-	-	-	50,880
Restricted Stock and Units	-	-	11,080	(18,573)	-	-	7,493	-
Amortization of Unearned Compensation	-	-	-	12,188	-	-	-	12,188
Treasury Stock Issued as Compensation	-	-	789	-	-	-	649	1,438
Balance at December 31, 2005	$ 99,062	$202,495	$ 84,705	$(36,246)	$177,137	$3,920,483	$(131,344)	$4,316,292

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	2005	2004	2003
Cash Flows From Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	$ 1,259,576	$ 624,855	$ 430,145
Items Not Requiring Cash			
Depreciation, Depletion and Amortization	654,258	504,403	441,843
Impairments	77,932	81,530	89,133
Deferred Income Taxes	270,291	204,231	191,726
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	-	7,131
Other, Net	9,642	4,580	1,033
Dry Hole Costs	64,812	92,142	41,156
Mark-to-Market Commodity Derivative Contracts			
Total (Gains) Losses	(10,475)	33,449	80,414
Realized Gains (Losses)	9,807	(82,644)	(44,870)
Collar Premium	-	(520)	(3,003)
Tax Benefits from Stock Options Exercised	50,880	29,396	11,926
Other, Net	(5,086)	537	2,141
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	(315,557)	(151,799)	(27,945)
Inventories	(23,085)	(17,898)	(2,840)
Accounts Payable	248,411	136,716	74,645
Accrued Taxes Payable	88,151	18,197	12,056
Other Liabilities	(1,213)	(1,764)	(3,257)
Other, Net	(10,347)	(2,683)	(15,314)
Changes in Components of Working Capital Associated with Investing and Financing Activities	1,429	(28,381)	(36,944)
Net Cash Provided by Operating Activities	2,369,426	1,444,347	1,249,176
Investing Cash Flows			
Additions to Oil and Gas Properties	(1,724,763)	(1,416,684)	(1,245,539)
Proceeds from Sales of Assets	70,987	13,459	13,553
Changes in Components of Working Capital Associated with Investing Activities	(1,538)	26,788	38,491
Other, Net	(22,794)	(20,471)	(13,946)
Net Cash Used in Investing Activities	(1,678,108)	(1,396,908)	(1,207,441)
Financing Cash Flows			
Net Commercial Paper and Line of Credit Repayments	(91,800)	(6,250)	(36,260)
Long-Term Debt Borrowings	250,000	150,000	-
Long-Term Debt Repayments	(250,755)	(175,000)	-
Dividends Paid	(42,986)	(37,595)	(31,294)
Redemption of Preferred Stock	-	(50,000)	-
Treasury Stock Purchased	-	-	(21,295)
Proceeds from Stock Options Exercised	64,668	75,510	35,138
Changes in Components of Working Capital Associated with Financing Activities	109	1,593	(1,547)
Other, Net	(1,546)	(1,496)	(1,938)
Net Cash Used in Financing Activities	(72,310)	(43,238)	(57,196)
Effect of Exchange Rate Changes on Cash	3,823	12,336	10,056
Increase (Decrease) in Cash and Cash Equivalents	622,831	16,537	(5,405)
Cash and Cash Equivalents at Beginning of Year	20,980	4,443	9,848
Cash and Cash Equivalents at End of Year	**$ 643,811**	**$ 20,980**	$ **4,443**

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

EOG RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

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

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

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, marketable securities, 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 Note 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 assessed quarterly on a property-by-property basis, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. 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. All other exploratory wells that do not meet these criteria are expensed after one year. As of December 31, 2005 and 2004, EOG had exploratory drilling costs related to two projects that have been deferred for more than one year (see Note 16). 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 of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. 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 are depreciated on a straight-line basis.

Assets are grouped in accordance with paragraph 30 of Statement of Financial Accounting Standards (SFAS) No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." 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.

EOG accounts for impairments under the provisions of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." When circumstances indicate that an asset may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

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 any reductions in value.

Arrangements for natural gas, crude oil, condensate and natural gas liquids sales are evidenced by signed contracts with determinable market prices and 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.

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 activities and not on proved properties. 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 SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149. The statement establishes accounting and reporting standards requiring that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value. The statement requires 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 ending December 31, 2005, EOG elected not to designate any of its commodity price risk management activities as accounting hedges under SFAS No. 133, and accordingly, accounted for them using the mark-to-market accounting method. Under this accounting method, the changes in the market 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).

Income Taxes. EOG accounts for income taxes under the provisions of SFAS No. 109, "Accounting for Income Taxes." SFAS No. 109 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. In accordance with the provisions of SFAS No. 128, "Earnings 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 Options. EOG accounted for stock options under the provisions and related interpretations of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." No compensation expense was recognized for such options. As allowed by SFAS No. 123, "Accounting for Stock-Based Compensation" issued in 1995, EOG continued to apply APB Opinion No. 25 for purposes of determining net income and to present the pro forma disclosures required by SFAS No. 123.

EOG's pro forma net income and net income per share available to common for 2005, 2004 and 2003, had compensation costs been recorded in accordance with SFAS No. 123, are presented below (in millions, except per share data):

	2005	2004	2003
Net Income Available to Common - As Reported	$ 1,252.1	$ 614.0	$ 419.1
Deduct: Total Stock-Based Employee Compensation Expense, Net of Income Tax	(13.7)	(11.9)	(13.9)
Net Income Available to Common - Pro Forma	$ 1,238.4	$ 602.1	$ 405.2
Net Income Per Share Available to Common			
Basic - As Reported	$ 5.24	$ 2.63	$ 1.83
Basic - Pro Forma	$ 5.19	$ 2.58	$ 1.77
Diluted - As Reported	$ 5.13	$ 2.58	$ 1.80
Diluted - Pro Forma	$ 5.08	$ 2.53	$ 1.74

For all grants made prior to August 2004 and employee stock purchase plan grants, the fair value of each option grant is estimated using the Black-Scholes-Merton option-pricing model with the following weighted-average assumptions used for grants in 2005, 2004 and 2003, respectively: (1) dividend yield of 0.4%, 0.4% and 0.4%, (2) expected volatility of 30%, 35% and 43%, (3) risk-free interest rate of 3.0%, 2.5% and 3.4% and (4) expected life of 0.5 years, 2.8 years and 5.2 years.

Certain of EOG's stock options issued in 2005 and 2004 contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price reaches 200% of the grant price for five consecutive trading days (Capped Option). EOG may or may not issue Capped Options in the future. The fair value of each Capped Option grant is estimated using a Monte Carlo simulation with the following weighted-average assumptions: (1) dividend yield of 0.4%, (2) expected volatility of 33%, (3) risk-free interest rate of 4.3% and (4) expected life of 4.8 years. Effective May 2005, the fair value of stock option grants not containing the Capped Option feature is estimated using the Hull-White II binomial option pricing model with the following weighted-average assumptions: (1) dividend yield of 0.4%, (2) expected volatility of 32%, (3) risk-free interest rate of 4.2% and (4) expected life of 5.0 years. During 2005, approximately 1,934,000 stock options were granted at a weighted average fair value of $19.25 and were included in the above pro forma employee stock based compensation expense calculation. Approximately 111,000 of the stock options were granted with an average fair value of $9.81, based on the Black-Scholes-Merton option-pricing model. Approximately 136,000 of the stock options were granted with the Capped Option feature with an average fair value of $17.36, based on the Monte Carlo simulation. Approximately 1,687,000 of the stock options were granted without the Capped Option feature with an average fair value of $20.02, based on the Hull-White II binomial option pricing model. The weighted average fair values for the stock options granted during 2004 and 2003 were $21.06 and $16.55, respectively.

The effects of applying SFAS No. 123 in this pro forma disclosure should not be interpreted as being indicative of future effects. SFAS No. 123 does not apply to awards prior to 1995, and the extent and timing of additional future awards cannot be predicted.

Recently Issued Accounting Standards and Developments. In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF Issue 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. EOG presents purchase and sale activities related to its marketing activities on a net basis in the Consolidated Statements of Income and Comprehensive Income. The adoption of EITF Issue No. 04-13 is not expected to have a material impact on EOG's financial statements.

In April 2005, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. 19-1, "Accounting for Suspended Well Costs," which amended SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." FSP No. 19-1 allows exploratory well costs to continue to be capitalized beyond one year of the drilling completion date when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. EOG adopted FSP No. 19-1 effective July 1, 2005. The adoption of FSP No. 19-1 did not have a material impact on EOG's financial statements. (See Note 16.)

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

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

In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment," which supersedes SFAS No. 148, "Accounting for Stock Based Compensation - Transition and Disclosure, an amendment of FASB Statement No. 123." SFAS No. 123(R) establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This eliminates the exception to account for such awards using the intrinsic method previously allowable under APB Opinion No. 25. SFAS No. 123(R) is effective for annual reporting periods beginning on or after June 15, 2005. EOG adopted SFAS No. 123(R) effective January 1, 2006 using the modified prospective method. EOG expects this will reduce 2006 net earnings by a pre-tax amount of approximately $25 million, taking into consideration the estimated forfeitures and cancellations. The amount includes approximately $21 million of expense for unvested options outstanding at December 31, 2005 and $1 million of expense for the Employee Stock Purchase Plan. SFAS No. 123(R) also requires a public entity to present its cash flows provided by tax benefits from stock options exercised in the Financing Cash Flows section of the Statement of Cash Flows. Had SFAS No. 123(R) been in effect, EOG's Net Cash Provided by Operating Activities would have been reduced and its Net Cash Provided by Financing Activities would have been increased on its Consolidated Statements of Cash Flows by $51 million, $29 million and $12 million for 2005, 2004 and 2003, respectively (see Note 6).

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was enacted. The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010. The Act also provides for a two-year phase out of the existing extra-territorial income exclusion (ETI) for foreign sales that was held to be inconsistent with international trade protocols. EOG expects the net effect of the phase in of the domestic production activities deduction and the phase out of the ETI to result in favorable adjustments to the effective tax rate for 2005 and subsequent years. Under the guidance in FSP No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004," the deduction will be treated as a "special deduction" as described in SFAS No. 109. As such, the special deduction has no effect on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction will be reported in the period in which the deduction is claimed on EOG's tax return. (See Note 5.)

The Act also creates a temporary incentive for United States corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. On October 28, 2005, EOG's Board of Directors approved EOG's Domestic Reinvestment Plan under which the categories of qualified expenditures are workers compensation and infrastructure and capital investments in the United States. During December 2005, EOG received a $450 million foreign dividend qualifying under the Act and recorded a tax charge of approximately $24 million as a result of the transaction.

On April 1, 2004, EOG adopted prospectively FSP No. 106-2, "Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-2), which provides guidance on accounting for the effects of the Medicare Prescription Drug Improvement Act of 2003 for employers that sponsor postretirement health care plans that provide prescription drug benefits. The adoption of FSP 106-2 did not have a material impact on EOG's financial statements (see Note 6).

2. Long-Term Debt

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

	2005	2004
Commercial Paper	$ -	$ 91,800
Senior Unsecured Term Loan Facility due 2005	-	75,000
6.70% Notes due 2006	126,075	126,870
6.50% Notes due 2007	98,992	100,000
6.00% Notes due 2008	-	173,952
6.65% Notes due 2028	140,000	140,000
Subsidiary Senior Unsecured Term Loan Facility due 2008	250,000	-
7.00% Subsidiary Debt due 2011	220,000	220,000
4.75% Subsidiary Debt due 2014	150,000	150,000
	985,067	1,077,622
Less: Current Portion of Long-Term Debt	126,075	-
Total	**$ 858,992**	**$ 1,077,622**

During 2005 and 2004, EOG utilized commercial paper, bearing market interest rates, for various corporate financing purposes. Commercial paper outstanding at December 31, 2004 was classified as long-term debt based on EOG's intent and ability to ultimately replace such amounts with other long-term debt. The weighted average interest rate for commercial paper was 3.30% for 2005. At December 31, 2005, the aggregate annual maturities of long-term debt were $126 million in 2006, $99 million in 2007, $250 million in 2008 and zero in both 2009 and 2010.

In accordance with notice delivered to holders on November 1, 2005, EOG redeemed the remaining $174 million outstanding principal amount of its 6.00% Notes due 2008 (2008 Notes) on December 5, 2005, at a redemption price of $1,039.22 per each $1,000.00 of principal amount, plus accrued and unpaid interest through the redemption date. The redemption was made in accordance with terms of the indenture and the officer's certificate establishing the terms of the 2008 Notes. In connection with the redemption, EOG recognized a loss on extinguishment of debt in the amount of $8 million, included in Net Interest Expense, representing prepaid interest and the write-off of deferred bond issuance costs.

In October 2005, EOGI International Company (EOGI) a wholly owned foreign subsidiary of EOG entered into a $600 million, 3-year unsecured Senior Term Loan Agreement (Term Loan Agreement) with The Bank of Nova Scotia, as Administrative Agent, and certain banks, as lenders. All borrowings under this agreement will be made as term loans and will be guaranteed by EOG. Proceeds from the Term Loan Agreement are to be used for general corporate purposes, including funding distributions ultimately to EOG from its foreign subsidiaries to realize a benefit of the favorable United States tax legislation regarding repatriation of foreign earnings under the American Jobs Creation Act of 2004. Borrowings up to $600 million under the Term Loan Agreement were available in multiple drawings through December 31, 2005, and prior to such date, EOGI elected to borrow $250 million, which was used to fund the distributions ultimately to EOG as described above. The $250 million was borrowed at the Eurodollar rate (a London InterBank Offering Rate (LIBOR) plus the applicable margin) of 4.90% per annum for the initial three-month interest period beginning December 6, 2005. Subsequent to December 31, 2005, borrowing capacity under the Term Loan Agreement was reduced to $100 million and such amount will be available for an additional one-year period. On February 17, 2006, EOGI repaid $50 million of the amount outstanding at December 31, 2005. Borrowings under the Term Loan Agreement accrue interest at LIBOR plus an applicable margin or at the Administrative Agent's base rate, as selected by the borrower.

On June 28, 2005, EOG entered into a new 5-year $600 million unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders and JPMorgan Chase Bank, N.A., as Administrative Agent, and concurrently terminated the existing $600 million 3-year unsecured credit facility scheduled to expire in July 2006. Under the Agreement, EOG has the option to extend, as to consenting lenders, the term for successive one-year periods with the consent of the majority banks and to request increases in the aggregate commitments to an amount not to exceed $1 billion. The Agreement also provides for the allocation, at the option of EOG, of up to $75 million of the $600 million each to EOG's current United Kingdom subsidiary and one of its Canadian subsidiaries. Interest accrues on advances at LIBOR plus an applicable margin (Eurodollar rate) or at the Administrative Agent's base rate, as selected by EOG. Advances to the Canadian or the United Kingdom subsidiaries, should they occur, would be guaranteed by EOG and would bear interest at a rate calculated in accordance with the Agreement. In addition, the Agreement provides EOG the option to request letters of credit to be issued in an aggregate amount of up to $200 million. There are no borrowings or letters of credit currently outstanding under the Agreement. At December 31, 2005, the applicable base rate and Eurodollar rate, had there been an amount borrowed under the Agreement, would have been 7.25% and 4.58%, respectively.

Both EOG's $600 million Long-Term Revolving Credit Agreement and EOGI's Term Loan Agreement contain certain restrictive covenants applicable to EOG, including a maximum debt-to-total capitalization ratio of 65%. Other than this financial covenant, there are no other financial covenants in EOG's financing agreements. EOG continues to comply with this covenant and does not view it as materially restrictive.

On September 15, 2004, EOG paid in full upon maturity the $100 million, 6.50% Notes.

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 Canadian Dollars (CAD) 201.3 million with a 5.275% interest rate.

EOG maintained a $150 million three-year Senior Unsecured Term Loan Facility (Facility) with a group of banks with a maturity date of October 30, 2005. The Facility accrued interest at LIBOR plus an applicable margin, or the base rate, at EOG's option, and contained substantially the same covenants as those in EOG's $600 million Long-Term Revolving Credit Agreement. On March 31, 2004, EOG repaid $75 million of the $150 million loan. The applicable interest rate for the Facility was 3.17% at December 31, 2004. On August 26, 2005, EOG repaid the remaining $75 million outstanding under the Facility and terminated the Facility.

The 6.00% to 6.70% Notes due 2006 to 2028 were issued through public offerings and have effective interest rates of 6.16% to 6.81%. The Subsidiary Debt due 2011 bears interest at a fixed rate of 7.00% and is guaranteed by EOG.

Shelf Registration. As of February 22, 2006, the amount available under various filed registration statements with the Securities and Exchange Commission for the offer and sale from time to time of EOG debt securities, preferred stock and/or common stock totaled approximately $688 million.

Fair Value of Current and Long-Term Debt. At December 31, 2005 and 2004, EOG had $985 million and $1,078 million, respectively, of long-term debt (including current portion), which had fair values of approximately $1,025 million and $1,146 million, respectively. The fair value of long-term debt is the value EOG would have to pay to retire the debt, including any premium or discount to the debt-holder for the differential between the stated interest rate and the year-end market rate. The fair value of long-term debt is based upon quoted market prices and, where such quotes were not available, upon interest rates available to EOG at year-end.

3. Shareholders' Equity

Common Stock. EOG purchases its common stock from time to time in the open market to be 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 common stock shall be required. In September 2001, the Board of Directors authorized the purchase of an aggregate maximum of 10 million shares of common stock of EOG which superseded all previous authorizations. At December 31, 2005, 6,386,200 shares remain available for repurchases under this authorization. On February 2, 2005, EOG announced that the Board of Directors had approved a two-for-one stock split in the form of a stock dividend, payable to record holders as of February 15, 2005 and issued on March 1, 2005. In addition, the Board increased the quarterly cash dividend on the common stock to a quarterly cash dividend of $0.04 per share post-split. On February 1, 2006, the Board increased the quarterly cash dividend on the common stock to $0.06 per share.

The following summarizes shares of common stock outstanding at December 31, for each of the years ended December 31 (in thousands):

	Common Shares		
	Issued	**Treasury**	**Outstanding**
Balance at December 31, 2002	249,460	(20,019)	229,441
Treasury Stock Purchased	-	(1,252)	(1,252)
Treasury Stock Issued under Stock Option Plans	-	2,971	2,971
Treasury Stock Issued Under Employee Stock Purchase Plan	-	148	148
Restricted Stock and Units	-	494	494
Treasury Stock Issued as Compensation	-	19	19
Balance at December 31, 2003	249,460	(17,639)	231,821
Treasury Stock Purchased	-	(320)	(320)
Treasury Stock Issued Under Stock Option Plans	-	5,922	5,922
Treasury Stock Issued Under Employee Stock Purchase Plan	-	136	136
Restricted Stock and Units	-	296	296
Balance at December 31, 2004	249,460	(11,605)	237,855
Treasury Stock Purchased	-	(155)	(155)
Treasury Stock Issued Under Stock Option Plans	-	3,804	3,804
Treasury Stock Issued Under Employee Stock Purchase Plan	-	106	106
Restricted Stock and Units	-	464	464
Balance at December 31, 2005	249,460	(7,386)	242,074

On February 14, 2000, EOG's Board of Directors declared a dividend of one preferred share purchase right (a Right, and the agreement governing the terms of such Rights, the Rights Agreement) for each outstanding share of common stock, par value $0.01 per share. The Board of Directors has adopted this Rights Agreement to protect stockholders from coercive or otherwise unfair takeover tactics. The dividend was distributed to the stockholders of record on February 24, 2000. As mentioned above, on March 1, 2005, EOG effected a two-for-one stock split in the form of a stock dividend. In accordance with the Rights Agreement, each share of common stock issued in connection with the two-for-one stock split effective March 1, 2005 also had one Right associated with it. Each Right, expiring February 24, 2010, represents a right to buy from EOG one hundredth (1/100) of a share of Series E Junior Participating Preferred Stock (Series E) for $90, once the Rights become exercisable. This portion of a Series E share will give the stockholder approximately the same dividend, voting, and liquidation rights as would one share of common stock. Prior to exercise, the Right does not give its holder any dividend, voting, or liquidation rights. If issued, each one hundredth (1/100) of a Series E share (i) will not be redeemable; (ii) will entitle holders to quarterly dividend payments of $0.01 per share, or an amount equal to the dividend paid on one share of common stock, whichever is greater; (iii) will entitle holders upon liquidation either to receive $1 per share or an amount equal to the payment made on one share of common stock, whichever is greater; (iv) will have the same voting power as one share of common stock; and (v) if shares of EOG's common stock are exchanged via merger, consolidation, or a similar transaction, will entitle holders to a per share payment equal to the payment made on one share of common stock.

The Rights will not be exercisable until ten days after a public announcement that a person or group has become an acquiring person (Acquiring Person) by obtaining beneficial ownership of 10% or more of EOG's common stock, or if earlier, ten business days (or a later date determined by EOG's Board of Directors before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if consummated, would result in that person or group becoming an Acquiring Person. On February 24, 2005, the Rights Agreement was amended to create an exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more but less than 20% of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the following requirements: (i) the institutional investor is described in Rule 13d-1(b)(1) promulgated under the Securities Exchange Act of 1934 and is eligible to report (and, if such institutional investor is the beneficial owner of greater than 5% of EOG's common stock, does in fact report) beneficial ownership of common stock on Schedule 13G; (ii) the institutional investor is not required to file a Schedule 13D (or any successor or comparable report) with respect to its beneficial ownership of EOG's common stock; (iii) the institutional investor does not beneficially own 15% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates other than those which, under published interpretations of the United States Securities and Exchange Commission or its staff, are eligible to file separate reports on Schedule 13G with respect to their beneficial ownership of EOG's common stock); and (iv) the institutional investor does not beneficially own 20% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates). On June 15, 2005, the Rights Agreement was amended again to revise the exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more but less than 30% of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the other requirements described above.

If a person or group becomes an Acquiring Person, all holders of Rights, except the Acquiring Person, may for $90, purchase shares of EOG's common stock with a market value of $180, based on the market price of the common stock prior to such acquisition. If EOG is later acquired in a merger or similar transaction after the Rights become exercisable, all holders of Rights except the Acquiring Person may, for $90, purchase shares of the acquiring corporation with a market value of $180 based on the market price of the acquiring corporation's stock, prior to such merger.

EOG's Board of Directors may redeem the Rights for $0.005 per Right at any time before any person or group becomes an Acquiring Person. If the Board of Directors redeems any Rights, it must redeem all of the Rights. Once the Rights are redeemed, the only right of the holders of Rights will be to receive the redemption price of $0.005 per Right. The redemption price has been adjusted for the two-for-one stock split effective March 1, 2005 and will be adjusted for any future stock split or stock dividends of EOG's common stock. After a person or group becomes an Acquiring Person, but before an Acquiring Person owns 50% or more of EOG's outstanding common stock, the Board of Directors may exchange the Rights for common stock or equivalent security at an exchange ratio of one share of common stock or an equivalent security for each such Right, other than Rights held by the Acquiring Person.

Preferred Stock. EOG currently has two authorized series of preferred stock. On February 14, 2000, EOG's Board of Directors, in connection with the Rights Agreement described above, authorized 1,500,000 shares of the Series E with the rights and preferences described above. On February 24, 2005, EOG's Board of Directors increased the authorized shares of the Series E to 3,000,000 as a result of the two-for-one stock split of EOG's common stock effective March 1, 2005. Currently, there are no shares of the Series E outstanding.

On July 19, 2000, EOG's Board of Directors authorized 100,000 shares of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 Liquidation Preference per share (the Series B). Dividends are payable on the shares only if declared by EOG's Board of Directors and will be cumulative. If declared, dividends will be payable at a rate of $71.95 per share, per year on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. EOG may redeem all or part of the Series B at any time beginning on December 15, 2009 at $1,000 per share, plus accrued and unpaid dividends. The Series B is not convertible into, or exchangeable for, common stock of EOG. There are 100,000 shares of the Series B currently outstanding.

Following the December 2004 redemption of all outstanding shares of EOG's Flexible Money Market Cumulative Preferred Stock, Series D, EOG filed a Certificate of Elimination with the Secretary of State of the State of Delaware on February 24, 2005 to eliminate the series from EOG's Restated Certificate of Incorporation, as amended.

4. Other Income, Net

Other income, net for 2005 consisted of equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants of $16 million, gains on sales of properties of $13 million, interest income of $8 million, a gain on the sale of part of EOG’s interest in the N2000 ammonia plant of $2 million and net foreign currency transaction losses of $2 million. Other income, net for 2004 consisted of equity income from investments in the CNCL and N2000 ammonia plants of $11 million, foreign currency transaction losses of $7 million, and gains on sales of properties of $6 million. The foreign currency transaction gains and losses for 2005 and 2004 were results of fluctuations in the Canadian Dollar and British Pound exchange rates applied to certain intercompany short-term loans, which were eliminated during consolidation.

5. Income Taxes

The principal components of EOG's net deferred income tax liability at December 31 were as follows (in thousands):

	2005	2004
Current Deferred Income Tax Assets		
Commodity Hedging Contracts	$ (7,995)	$ (7,701)
Deferred Compensation Plans	7,366	6,488
United Kingdom Net Operating Loss Carryforward (Current Portion)	7,592	10,160
Other	17,413	13,280
Total Current Deferred Income Tax Assets	24,376	22,227
Current Deferred Income Tax Liabilities		
Timing Differences Associated With Different Year-ends in Foreign Jurisdictions	164,659	103,903
Other	-	30
Total Current Deferred Income Tax Liabilities	164,659	103,933
Total Net Current Deferred Income Tax Liabilities	**$ 140,283**	**$ 81,706**
Noncurrent Deferred Income Tax Assets (included in Other Assets)		
United Kingdom Net Operating Loss Carryforward	$ -	$ 21,764
United Kingdom Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	(16,939)	(20,465)
Total Noncurrent Deferred Income Tax Assets	**$ (16,939)**	**$ 1,299**
Noncurrent Deferred Income Tax Assets		
Non-Producing Leasehold Costs	$ 51,130	$ 41,718
Seismic Costs Capitalized for Tax	41,328	25,563
Other	39,211	22,740
Total Noncurrent Deferred Income Tax Assets	131,669	90,021
Noncurrent Deferred Income Tax Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	1,209,494	974,492
Capitalized Interest	21,332	16,683
Other	6,492	1,200
Total Noncurrent Deferred Income Tax Liabilities	1,237,318	992,375
Total Net Noncurrent Deferred Income Tax Liability	**$ 1,105,649**	**$ 902,354**
Total Net Deferred Income Tax Liability	**$ 1,262,871**	**$ 982,761**

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

	2005	2004	2003
United States	$ 1,336,658	$ 641,973	$ 442,109
Foreign	628,479	284,039	211,767
Total	**$ 1,965,137**	**$ 926,012**	**$ 653,876**

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

	2005	2004	2003
Current:			
Federal	$ 333,752	$ 58,148	$ 3,844
State	25,527	3,137	880
Foreign	75,991	35,641	20,150
Total	435,270	96,926	24,874
Deferred:			
Federal	132,118	156,862	151,389
State	14,774	7,985	4,052
Foreign	123,399	39,384	36,285
Total	270,291	204,231	191,726
Income Tax Provision	**$ 705,561**	**$ 301,157**	**$ 216,600**

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

	2005	2004	2003
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	1.32	0.74	0.73
Income Tax Provision Related to Foreign Operations	(0.92)	(1.83)	(0.05)
Change in Canadian Federal Tax Rate	-	-	(2.16)
Change in Canadian Provincial Tax Rate	-	(0.58)	-
Dividend Repatriation	1.20	-	-
Domestic Production Activities Deduction	(0.42)	-	-
Other	(0.28)	(0.81)	(0.40)
Effective Income Tax Rate	35.90%	32.52%	33.12%

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was enacted. The Act creates a temporary incentive for United States corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. During the fourth quarter of 2005, EOG made a qualifying distribution in the amount of $450 million resulting in a federal income tax of approximately $24 million.

EOG's foreign subsidiaries' undistributed earnings of approximately $1.3 billion at December 31, 2005 are considered to be indefinitely invested outside the United States and, accordingly, no United States 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.

EOG incurred a tax net operating loss of $191 million in 2002. During 2003, EOG utilized $176 million of the 2002 net operating loss. The remaining net operating loss of $15 million was utilized in 2004.

Through 2004, EOG incurred foreign net operating losses of approximately $70 million, of which $51 million was utilized in 2005. The remaining $19 million net operating loss will be carried forward indefinitely.

EOG had an alternative minimum tax credit carryforward from prior years of $6 million which was used to offset regular income taxes in 2004.

6. Employee Benefit Plans

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. For 2005, 2004 and 2003, EOG's total contributions to these pension plans amounted to $12 million, $11 million and $8 million, respectively.

In addition, EOG's Canadian subsidiary maintains both a 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 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 pension plans were approximately $2.0 million, $0.9 million and $0.5 million for 2005, 2004 and 2003, respectively.

The benefit obligation, fair value of plan assets and prepaid (accrued) benefit cost of the defined benefit pension plans totaled $6.4 million, $5.3 million and ($1.1) million, respectively, at December 31, 2005 and $1.0 million, $1.4 million and $0.2 million, respectively, at December 31, 2004. Weighted average discount rate and expected return on plan assets assumptions used to determine benefit obligations for the pension plans were 5.54% and 4.18%, respectively, at December 31, 2005 and 6.50% and 5.50%, respectively, at December 31, 2004. Weighted average discount rate assumptions used to determine net periodic benefit cost for the pension plans for the years ended December 31, 2005, 2004 and 2003 were 6.50%, 6.50% and 8.00%, respectively. The weighted average asset allocation of the pension plans at December 31, 2005 consisted of equities (57%), debt and fixed income securities (38%) and other assets (5%). The asset allocation at December 31, 2004 consisted of equities (54%), debt and fixed income securities (39%) and other (7%).

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 restricts 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 of Canadian balanced funds and in one or more foreign equity funds as deemed appropriate for the purposes of diversification.

EOG's United Kingdom subsidiary introduced a pension plan as of January 2005, 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 2005.

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 $3.4 million and $2.0 million, respectively, at December 31, 2005 and $2.1 million and $1.7 million, respectively, at December 31, 2004. Weighted average discount rate assumptions used to determine benefit obligations for the postretirement plans at December 31, 2005 and 2004 were 5.67% and 5.98%, respectively. Weighted average discount rate assumptions used to determine net periodic benefit cost for the years ended December 31, 2005, 2004 and 2003 were 5.98%, 6.15% and 6.40% for the postretirement plans. Net periodic benefit cost recognized for the postretirement benefit plans totaled $0.4 million, $0.5 million and $0.4 million for the years ended December 31, 2005, 2004 and 2003.

Accrued/(prepaid) benefit cost recognized in the Consolidated Balance Sheets at December 31, 2005 and 2004 totaled $1.1 million and ($0.2) million, respectively, for the pension plan and $2.0 million and $1.7 million, respectively, for the postretirement plan.

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
2006	$ 161	$ 121
2007	196	135
2008	197	146
2009	229	186
2010	285	211
2011 - 2015	1,700	1,585

Postretirement health care trend rates have minimal effect on the amounts reported for the postretirement health care plans for both 2005 and 2004. Most increases or decreases in healthcare costs would be borne by the employee.

Stock Plans

EOG has various stock plans (Plans) under which employees and non-employee members of the Board of Directors of EOG and its subsidiaries have been or may be granted certain equity compensation. Since the inception of the Plans, there have been 31,445,000 shares authorized for grant. At December 31, 2005, 5,606,109 shares remain available for grant.

Stock Options. Under the Plans, participants have been or may be granted rights to purchase shares of common stock of EOG at a price not less than the market price of the stock at the date of grant. Stock options granted under the Plans vest either immediately at the date of grant or 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 Plans have not exceeded a maximum term of 10 years.

Certain of EOG's stock options issued in 2005 and 2004 contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price reaches 200% of the grant price for five consecutive trading days (Capped Option). EOG may or may not issue Capped Options in the future.

The following table sets forth the option transactions for the years ended December 31 (options in thousands):

	2005		2004		2003	
	Options	Average Grant Price	Options	Average Grant Price	Options	Average Grant Price
Outstanding at January 1	11,922	$19.66	15,497	$15.19	15,674	$13.66
Granted	1,823	61.57	2,619	31.97	3,029	19.57
Exercised	(3,804)	17.61	(5,922)	13.43	(2,971)	11.37
Forfeited	(243)	28.86	(272)	19.34	(235)	17.37
Outstanding at December 31	9,698	28.12	11,922	19.66	15,497	15.19
Options Exercisable at December 31	4,575	16.61	6,104	15.18	9,861	13.52
Available for Future Grant	5,606		7,418		2,355	

EOG adopted SFAS No. 123(R) effective January 1, 2006 (see Note 1) and as a result, EOG expects the expensing of the stock options would reduce 2006 net earnings by a pre-tax amount of approximately $24 million.

The following table summarizes certain information for the options outstanding at December 31, 2005 (options in thousands):

	Options Outstanding			Options Exercisable	
Range of Grant Prices	**Options**	**Weighted Average Remaining Life (Years)**	**Weighted Average Grant Price**	**Options**	**Weighted Average Grant Price**
\$7.00 to \$14.99	726	3	\$ 8.88	726	\$ 8.88
15.00 to 16.99	2,139	6	16.72	1,604	16.68
17.00 to 19.99	2,926	7	18.81	1,954	18.48
20.00 to 31.99	452	7	24.00	290	22.95
32.00 to 48.99	1,782	9	33.34	1	36.55
49.00 to 78.99	1,673	7	62.86	-	62.98
	9,698	**6**	**28.12**	**4,575**	**16.61**

During 2005, 2004 and 2003, EOG repurchased approximately 155,000, 320,000 and 1,252,000 of its common shares, respectively. The difference between the cost of the treasury shares and the exercise price of the options, net of federal income tax benefit of \$51 million, \$29 million and \$12 million, for 2005, 2004 and 2003, respectively, is reflected as an adjustment to additional paid in capital to the extent EOG has accumulated additional paid in capital relating to treasury stock and to retained earnings thereafter.

Restricted Stock and Units. Under the Plans, employees may be granted restricted stock and/or units without cost to them. The shares and units granted vest to the employee at various times ranging from one to five years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Upon vesting, restricted shares are released to the employee. Upon vesting, each restricted unit is converted into one share of common stock and released to the employee. The following summarizes shares of restricted stock and units granted for the three years ended December 31 (shares and units in thousands):

	Restricted Shares and Units		
	2005	**2004**	**2003**
Outstanding at January 1	2,566	2,052	1,550
Granted	385	659	744
Released	(353)	(82)	(206)
Forfeited or Expired	(54)	(63)	(36)
Outstanding at December 31	2,544	2,566	2,052
Average Fair Value of Shares Granted During Year	\$ 52.19	\$ 25.71	\$ 20.21

The fair value of the restricted shares and units at date of grant has been recorded in shareholders' equity as unearned compensation and is being amortized over the vesting period as compensation expense. Related compensation expense for 2005, 2004 and 2003 was \$12 million, \$10 million and \$6 million, respectively.

Employee Stock Purchase Plan. EOG has an Employee Stock Purchase Plan (ESPP) in place that 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 employees' pay (subject to certain ESPP limits) during each of the two six-month offering periods. As of December 31, 2005, approximately 407,400 common shares remained available for issuance under the ESPP. EOG adopted SFAS No. 123(R) effective January 1, 2006 (see Note 1) and as a result, EOG expects the expense associated with the ESPP would reduce 2006 net earnings by a pre-tax amount of approximately $1 million.

The following table summarizes ESPP activities for the years ended December 31 (in thousands, except number of participants):

	2005	**2004**	**2003**
Approximate Number of Participants	580	450	410
Shares Purchased	106	136	148
Aggregate Purchase Price	$3,889	$3,021	$2,599

7. Commitments and Contingencies

Letters of Credit. At December 31, 2005, EOG had standby letters of credit and guarantees outstanding totaling approximately $711 million of which $620 million represents guarantees of subsidiary indebtedness included under Note 2 "Long-Term Debt" and $91 million primarily represents guarantees of payment obligations on behalf of subsidiaries. At December 31, 2004, EOG had standby letters of credit and guarantees outstanding totaling approximately $433 million of which $370 million represents guarantees of subsidiary indebtedness and $63 million primarily represents guarantees of payment obligations on behalf of subsidiaries. As of February 22, 2006, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2005, 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 CAD and British Pounds into United States Dollars at December 31, 2005, are as follows (in thousands):

	Total Minimum Commitments
2006	$ 166,132
2007 - 2009	228,565
2010 - 2011	67,154
2012 and beyond	89,376
	$ 551,227

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2016. Rental expenses associated with these leases amounted to $34 million, $26 million and $22 million for 2005, 2004 and 2003, respectively.

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

8. Net Income Per Share Available to Common

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

	2005	2004	2003
Numerator for basic and diluted earnings per share -			
Net Income Available to Common	$ 1,252,144	$ 613,963	$ 419,113
Denominator for basic earnings per share -			
Weighted average shares	238,797	233,751	229,194
Potential dilutive common shares -			
Stock options	3,942	3,561	3,168
Restricted stock and units	1,236	1,064	675
Denominator for diluted earnings per share -			
Adjusted weighted average shares	243,975	238,376	233,037
Net Income Per Share Available to Common			
Basic	$ 5.24	$ 2.63	$ 1.83
Diluted	$ 5.13	$ 2.58	$ 1.80

9. Supplemental Cash Flow Information

Cash paid for interest and income taxes was as follows for the years ended December 31 (in thousands):

	2005	2004	2003
Interest	$ 60,467	$ 60,967	$ 62,472
Income taxes	335,628	56,654	26,330

10. Business Segment Information

EOG's operations are all natural gas and crude oil exploration and production related. SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," 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 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 and each of its significant international locations. For segment reporting purposes, the major United States producing areas have been aggregated as one reportable segment due to similarities in their operations as allowed by SFAS No. 131.

Financial information by reportable segment is presented below for the years ended December 31, or at December 31 (in thousands):

	United States	Canada	Trinidad	United Kingdom	Other	Total
2005						
Net Operating Revenues[(1)]	$ 2,584,017	$ 651,348	$ 280,622	$ 104,226	$ -	$ 3,620,213
Depreciation, Depletion and Amortization	488,621	124,793	24,781	16,063	-	654,258
Operating Income	1,356,267	377,580	204,133	53,835	-	1,991,815
Interest Income	1,218	2,139	4,510	-	-	7,867
Other Income (Expense)	19,351	(5,029)	17,631	(3,992)	-	27,961
Interest Expense, Net	38,683	22,843	909	71	-	62,506
Income Before Income Taxes	1,338,153	351,847	225,365	49,772	-	1,965,137
Income Tax Provision	485,523	110,794	88,919	20,325	-	705,561
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	1,299,205	307,862	42,384	10,500	-	1,659,951
Net Oil and Gas Properties	4,009,700	1,757,123	277,113	43,243	-	6,087,179
Total Assets	5,176,701	1,958,655	538,671	79,293	-	7,753,320
2004						
Net Operating Revenues[(2)]	$ 1,656,325	$ 448,562	$ 153,377	$ 12,961	$ -	$ 2,271,225
Depreciation, Depletion and Amortization	382,718	99,879	20,022	1,784	-	504,403
Operating Income (Loss)	682,619	222,155	91,245	(16,824)	-	979,195
Interest Income	292	679	659	-	-	1,630
Other Income (Expense)	1,072	(4,487)	10,892	838	-	8,315
Interest Expense, Net	41,571	21,415	-	142	-	63,128
Income (Loss) Before Income Taxes	642,412	196,932	102,796	(16,128)	-	926,012
Income Tax Provision (Benefit)	231,250	45,785	31,414	(7,292)	-	301,157
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	936,463	294,571	59,205	34,303	-	1,324,542
Net Oil and Gas Properties	3,276,718	1,515,414	256,858	52,613	-	5,101,603
Total Assets	3,727,231	1,600,486	401,434	69,772	-	5,798,923
2003						
Net Operating Revenues[(3)]	$ 1,335,145	$ 309,418	$ 100,112	$ -	$ -	$ 1,744,675
Depreciation, Depletion and Amortization	359,439	66,334	16,070	-	-	441,843
Operating Income (Loss)	487,133	163,783	55,433	(9,195)	160	697,314
Interest Income	1,385	950	454	-	-	2,789
Other Income (Expense)	2,777	6,354	3,418	(71)	6	12,484
Interest Expense, Net	43,421	14,618	670	-	2	58,711
Income (Loss) Before Income Taxes	447,874	156,469	58,635	(9,266)	164	653,876
Income Tax Provision (Benefit)	163,359	36,190	20,671	(3,486)	(134)	216,600
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	605,667	552,164	31,942	14,610	-	1,204,383
Net Oil and Gas Properties	2,775,504	1,243,341	215,376	14,696	-	4,248,917
Total Assets	3,119,474	1,302,753	309,727	17,061	-	4,749,015

(1) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2005 that totaled $385 million of consolidated Net Operating Revenues.

(2) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2004 that totaled $280 million of consolidated Net Operating Revenues.

(3) EOG had sales activity with two significant purchasers, one totaled $222 million and the other totaled $182 million, of consolidated Net Operating Revenues in the United States and Canada segments in 2003.

11. Price, Interest Rate and Credit Risk Management Activities

Price and Interest Rate 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 collars and price swaps, as the 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 SFAS No. 133, 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 2005, 2004 and 2003, 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 mark-to-market accounting. During 2005, EOG recognized gains on mark-to-market financial commodity derivative contracts of $10 million, which included realized gains of $10 million. During 2004, EOG recognized losses on mark-to-market financial commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million. During 2003, EOG recognized losses on mark-to-market financial commodity derivative contracts of $80 million, which included realized losses of $45 million and collar premium payments of $3 million.

Presented below is a summary of EOG's 2006 natural gas financial collar and price swap contracts at December 31, 2005 with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units per day (MMBtud). The total fair value of the natural gas financial collar and price swap contracts at December 31, 2005 was $11 million.

Natural Gas Financial Contracts

	Collar Contracts					Price Swap Contracts	
		Floor Price		Ceiling Price			
Month	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
February (closed)	50,000	$13.65 - 14.50	$14.05	$16.20 - 17.04	$16.59	-	-
March	50,000	13.50 - 14.30	13.87	15.95 - 17.05	16.46	-	-
April	50,000	10.00 - 10.50	10.23	12.60 - 13.00	12.77	20,000	$10.48
May	50,000	9.75 - 10.00	9.87	12.15 - 12.60	12.31	20,000	10.33
June	50,000	9.75 - 10.00	9.87	12.20 - 12.60	12.34	20,000	10.37
July	50,000	9.75 - 10.00	9.87	12.35 - 12.85	12.50	20,000	10.39
August	50,000	9.75 - 10.00	9.87	12.50 - 13.00	12.67	20,000	10.44

Presented below is a summary of EOG's 2006 natural gas financial collar and price swap contracts at February 22, 2006:

Natural Gas Financial Contracts

	Collar Contracts					Price Swap Contracts	
		Floor Price		Ceiling Price			
Month	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
February (closed)	50,000	$13.65 - 14.50	$14.05	$16.20 - 17.04	$16.59	-	-
March	50,000	13.50 - 14.30	13.87	15.95 - 17.05	16.46	170,000	$9.54
April	50,000	10.00 - 10.50	10.23	12.60 - 13.00	12.77	180,000	9.49
May	50,000	9.75 - 10.00	9.87	12.15 - 12.60	12.31	180,000	9.50
June	50,000	9.75 - 10.00	9.87	12.20 - 12.60	12.34	180,000	9.54
July	50,000	9.75 - 10.00	9.87	12.35 - 12.85	12.50	190,000	9.57
August	50,000	9.75 - 10.00	9.87	12.50 - 13.00	12.67	190,000	9.63
September	-	-	-	-	-	140,000	9.40

October	-	-	-	-	-	90,000	9.46

The following table summarizes the estimated fair value of financial instruments and related transactions at December 31 of the years indicated as follows (in millions):

	2005		2004	
	Carrying Amount	Estimated Fair Value[(1)]	Carrying Amount	Estimated Fair Value[(1)]
Current and Long-Term Debt[(2)]	$ 985	$ 1,025	$ 1,078	$ 1,146
NYMEX-Related Commodity Market Positions	11	11	11	11

(1) Estimated fair values have been determined by using available market data and valuation methodologies. Judgment is required in interpreting market data and the use of different market assumptions or estimation methodologies may affect the estimated fair value amounts.

(2) See Note 2.

Credit Risk. While notional contract amounts are used to express the magnitude of commodity price and interest rate swap agreements, the amounts potentially subject to credit risk, in the event of nonperformance by the other parties, are substantially smaller. EOG evaluates its exposure to all 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, 2005, no individual purchaser's accounts receivable balance related to United States and Canada hydrocarbon sales accounted for 10% or more of the total balance. At December 31, 2004, EOG's net accounts receivable balance related to United States and Canada hydrocarbon sales included two receivable balances, each of which constituted 11% of the total balance. These receivables were due from two integrated oil and gas companies. The related amounts were collected during early 2005. No other individual purchaser accounted for 10% or more of the United States and Canada net accounts receivable balance at December 31, 2004. At December 31, 2005 and 2004, all of EOG's Trinidad receivables from natural gas sales were from the National Gas Company of Trinidad and Tobago.

At December 31, 2005, EOG had an allowance for doubtful accounts of $22 million, of which $19 million is associated with the Enron bankruptcies recorded in December 2001.

Substantially all of EOG's accounts receivable at December 31, 2005 and 2004 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 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, 2005 credit losses incurred on receivables by EOG have been immaterial.

12. Accounting for Certain Long-Lived Assets

EOG reviews its 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 2005, 2004 and 2003, 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 pre-tax charges of $31 million, $17 million and $21 million, in the United States operating segment during 2005, 2004 and 2003, respectively, and $8 million and $4 million in the Canada operating segment during 2004 and 2003, respectively. There were no pre-tax charges recorded in the Canada operating segment in 2005. The pre-tax 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 EOG's risk-adjusted discount rate. Amortization expenses of lease acquisition costs of unproved properties, including amortization of capitalized interest, were $47 million, $57 million and $64 million for 2005, 2004 and 2003, respectively.

13. Accounting for Asset Retirement Obligations

EOG adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003. The adoption of the statement resulted in an after-tax charge of $7 million, which was reported in the first quarter of 2003 as Cumulative Effect of Change in Accounting Principle. The following table presents the reconciliation of the beginning and ending aggregate carrying amount of short-term and long-term legal obligations associated with the retirement of oil and gas properties pursuant to SFAS No. 143 for 2005 (in thousands):

	Asset Retirement Obligations		
	Short-Term	**Long-Term**	**Total**
Balance at December 31, 2004	$ 6,970	$ 131,789	$ 138,759
Liabilities Incurred	45	8,404	8,449
Liabilities Settled	(3,559)	(2,406)	(5,965)
Accretions	183	7,499	7,682
Revisions	(555)	10,068	9,513
Reclassifications	3,082	(3,082)	-
Foreign Currency Translations	69	2,981	3,050
Balance at December 31, 2005	**$ 6,235**	**$ 155,253**	**$ 161,488**

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

EOG, through certain wholly owned subsidiaries, owns equity interests in two Trinidadian companies: CNCL and N2000. During the first quarters of 2005, 2004 and 2003, EOG completed separate share sale agreements whereby portions of the EOG subsidiaries' shareholdings in CNCL and N2000 were sold to a third party energy company. The sales left EOG with equity interests of 12% in CNCL and 10% in N2000 at December 31, 2005. The 2005 N2000 sale resulted in a pre-tax gain of $2 million. The 2003 and 2004 sales did not result in any gain or loss.

At December 31, 2005, the investment in CNCL was $18 million. CNCL commenced ammonia production in June 2002, and is currently producing approximately 1,900 metric tons of ammonia daily. At December 31, 2005, CNCL had a long-term debt balance of $173 million, which is non-recourse to CNCL's shareholders. EOG will 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 $30 million, approximately $4 million of which is net to EOG's interest. 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 2005, EOG recognized equity income of $9 million and received cash dividends of $5 million from CNCL.

At December 31, 2005, the investment in N2000 was $16 million. N2000 commenced ammonia production in August 2004, and is currently producing approximately 2,100 metric tons of ammonia daily. At December 31, 2005, N2000 had a long-term debt balance of $197 million, which is non-recourse to N2000's shareholders. At December 31, 2005, EOG was 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 $30 million, approximately $3 million of which is net to EOG's interest. 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 2005, EOG recognized equity income of $7 million and received cash dividends of $2 million from N2000.

15. Property Acquisitions

On October 1, 2003, a Canadian subsidiary of EOG closed an asset purchase of natural gas properties in the Wintering Hills, Drumheller East and Twining areas of southeast Alberta from a subsidiary of Husky Energy Inc. for approximately $320 million. These properties are essentially adjacent to existing EOG operations or are properties in which EOG already had a working interest. The transaction was partially funded by commercial paper borrowings of $140.5 million on October 1, 2003. The remainder of the purchase price, $179.5 million, was funded by EOG's available cash balance. Subsequent to the closing, the purchase price was reduced by exercised preferential rights on the properties which totaled approximately $5 million. In late December 2003, a Canadian subsidiary of EOG closed another property acquisition for $46 million.

16. Suspended Well Costs

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

	Year Ended December 31,		
	2005	2004	2003
Balance at January 1	$ 20,520	$ 14,964	$ 11,738
Additions Pending the Determination of Proved Reserves	18,533	15,634	10,143
Reclassifications to Proved Properties	(9,245)	(6,206)	(7,184)
Charged to Dry Hole Costs	(2,267)	(4,295)	-
Foreign Currency Translation	327	423	267
Ending Balance	$ 27,868	$ 20,520	$ 14,964

The following table provides an aging of suspended well costs for the years ended December 31, 2005, 2004 and 2003 (in thousands, except well count):

	Year Ended December 31,		
	2005	2004	2003
Capitalized exploratory well costs that have been capitalized for a period less than one year	$ 14,878	$ 16,270	$ 10,519
Capitalized exploratory well costs that have been capitalized for a period greater then one year	12,990 (1)	4,250 (2)	4,445 (2)
Total	$ 27,868	$ 20,520	$ 14,964
Number of exploratory wells that have been capitalized for a period greater than one year	2	1	1

(1) Costs as of December 31, 2005 related to an outside operated, deepwater offshore Gulf of Mexico discovery ($4 million) and an outside operated, winter access only, Northwest Territories discovery in Northern Canada ($9 million). EOG is continuing to evaluate these discoveries and plans to drill an additional exploratory well in each discovery.

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

Oil and Gas Producing Activities

The following disclosures are made in accordance with Statement of Financial Accounting Standards (SFAS) No. 69, "Disclosures about Oil and Gas Producing Activities":

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil and natural 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. 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.

Proved reserves represent estimated quantities of natural gas, crude oil, 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.

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

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 for completion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. 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 tests in the area and in the same reservoir.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates 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 reserves to be materially different from that presented.

Estimates of proved and proved developed reserves at December 31, 2005, 2004 and 2003 were based on studies performed by the engineering staff of EOG for all reserves. Opinions by DeGolyer and MacNaughton (D&M), independent petroleum consultants, for the years ended December 31, 2005, 2004 and 2003 covered producing areas containing 82%, 77% and 72%, 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 staff 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 staff of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG.

No major discovery or other favorable or adverse event subsequent to December 31, 2005 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, 2005, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2005, as estimated by the engineering staff of EOG.

NET PROVED AND PROVED DEVELOPED RESERVE SUMMARY

	United States	Canada	Trinidad	United Kingdom	TOTAL
NET PROVED RESERVES					
Natural Gas (Bcf)[1]					
Net proved reserves at December 31, 2002	2,006.2	777.9	1,306.5	-	4,090.6
Revisions of previous estimates	(24.9)	(18.5)	(74.9)	-	(118.3)
Purchases in place	43.9	361.0	-	-	404.9
Extensions, discoveries and other additions	345.5	118.3	129.3	59.2	652.3
Sales in place	(30.8)	-	-	-	(30.8)
Production	(238.3)	(60.2)	(55.4)	-	(353.9)
Net proved reserves at December 31, 2003	2,101.6	1,178.5	1,305.5	59.2	4,644.8
Revisions of previous estimates	(62.8)	(26.8)	34.2	-	(55.4)
Purchases in place	44.4	16.6	-	-	61.0
Extensions, discoveries and other additions	537.8	208.0	37.9	-	783.7
Sales in place	(1.3)	(0.6)	-	-	(1.9)
Production	(237.2)	(77.4)	(68.2)	(2.4)	(385.2)
Net proved reserves at December 31, 2004	2,382.5	1,298.3	1,309.4	56.8	5,047.0
Revisions of previous estimates	(21.3)	3.1	26.7	(22.6)	(14.1)
Purchases in place	30.2	-	-	-	30.2
Extensions, discoveries and other additions	835.9	104.7	-	15.0	955.6
Sales in place	(11.8)	-	-	-	(11.8)
Production	(267.4)	(83.3)	(84.5)	(14.3)	(449.5)
Net proved reserves at December 31, 2005	**2,948.1**	**1,322.8**	**1,251.6**	**34.9**	**5,557.4**

	United States	Canada	Trinidad	United Kingdom	TOTAL
Liquids (MBbl)[(2)]					
Net proved reserves at December 31, 2002	63,355	7,166	14,694	-	85,215
Revisions of previous estimates	1,487	214	(1,120)	-	581
Purchases in place	738	1,379	-	-	2,117
Extensions, discoveries and other additions	15,669	598	1,212	84	17,563
Sales in place	(344)	-	-	-	(344)
Production	(7,897)	(1,091)	(881)	-	(9,869)
Net proved reserves at December 31, 2003	73,008	8,266	13,905	84	95,263
Revisions of previous estimates	2,649	(116)	3,417	69	6,019
Purchases in place	157	1	-	-	158
Extensions, discoveries and other additions	9,859	920	229	-	11,008
Sales in place	(411)	(14)	-	-	(425)
Production	(9,474)	(1,290)	(1,291)	(9)	(12,064)
Net proved reserves at December 31, 2004	75,788	7,767	16,260	144	99,959
Revisions of previous estimates	3,539	1,361	(1,444)	4	3,460
Purchases in place	1,340	-	-	-	1,340
Extensions, discoveries and other additions	14,021	915	-	68	15,004
Sales in place	(410)	-	-	-	(410)
Production	(10,234)	(1,219)	(1,651)	(79)	(13,183)
Net proved reserves at December 31, 2005	**84,044**	**8,824**	**13,165**	**137**	**106,170**
Bcf Equivalent (Bcfe)[(1)]					
Net proved reserves at December 31, 2002	2,386.3	820.9	1,394.7	-	4,601.9
Revisions of previous estimates	(15.9)	(17.2)	(81.7)	-	(114.8)
Purchases in place	48.3	369.3	-	-	417.6
Extensions, discoveries and other additions	439.6	121.8	136.5	59.7	757.6
Sales in place	(32.9)	-	-	-	(32.9)
Production	(285.7)	(66.7)	(60.7)	-	(413.1)
Net proved reserves at December 31, 2003	2,539.7	1,228.1	1,388.8	59.7	5,216.3
Revisions of previous estimates	(47.0)	(27.5)	54.8	0.4	(19.3)
Purchases in place	45.4	16.6	-	-	62.0
Extensions, discoveries and other additions	597.0	213.5	39.3	-	849.8
Sales in place	(3.8)	(0.7)	-	-	(4.5)
Production	(294.1)	(85.1)	(75.9)	(2.5)	(457.6)
Net proved reserves at December 31, 2004	2,837.2	1,344.9	1,407.0	57.6	5,646.7
Revisions of previous estimates	(0.1)	11.3	18.1	(22.6)	6.7
Purchases in place	38.2	-	-	-	38.2
Extensions, discoveries and other additions	920.0	110.2	-	15.4	1,045.6
Sales in place	(14.2)	-	-	-	(14.2)
Production	(328.7)	(90.7)	(94.4)	(14.8)	(528.6)
Net proved reserves at December 31, 2005	**3,452.4**	**1,375.7**	**1,330.7**	**35.6**	**6,194.4**

	United States	Canada	Trinidad	United Kingdom	TOTAL
NET PROVED DEVELOPED RESERVES					
Natural Gas (Bcf)[1]					
December 31, 2002	1,658.7	683.3	555.2	-	2,897.2
December 31, 2003	1,749.3	889.2	429.9	-	3,068.4
December 31, 2004	1,855.7	1,070.1	760.9	56.8	3,743.5
December 31, 2005	2,090.6	1,141.0	703.9	28.8	3,964.3
Liquids (MBbl)[2]					
December 31, 2002	47,476	7,045	7,135	-	61,656
December 31, 2003	56,321	7,995	5,229	-	69,545
December 31, 2004	60,478	7,414	10,874	144	78,910
December 31, 2005	69,887	8,651	7,799	110	86,447
Bcf Equivalents (Bcfe)[1]					
December 31, 2002	1,943.6	725.5	598.0	-	3,267.1
December 31, 2003	2,087.3	937.2	461.2	-	3,485.7
December 31, 2004	2,218.5	1,114.7	826.2	57.6	4,217.0
December 31, 2005	2,509.9	1,192.9	750.7	29.5	4,483.0

(1) Billion cubic feet or billion cubic feet equivalent, as applicable.
(2) Thousand barrels; includes crude oil, condensate and natural gas liquids.

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 of the years indicated as follows:

	2005	2004
Proved properties	$ 10,784,191	$ 9,307,422
Unproved properties	389,198	291,854
Total	11,173,389	9,599,276
Accumulated depreciation, depletion and amortization	(5,086,210)	(4,497,673)
Net capitalized costs	**$ 6,087,179**	**$ 5,101,603**

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 SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" and SFAS No. 143, "Accounting for Asset Retirement Obligations."

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

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

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:

	United States	Canada	Trinidad	United Kingdom	Other	TOTAL
2005						
Acquisition Costs of Properties						
Unproved	$ 102,727	$ 24,278	$ 4,505	$ -	$ -	$ 131,510
Proved	55,477	468	-	-	-	55,945
Subtotal	158,204	24,746	4,505	-	-	187,455
Exploration Costs	286,862	42,426	19,924	18,040	2,844	370,096
Development Costs [1]	991,811	287,303	25,769	15,259	-	1,320,142
Total	$ 1,436,877	$ 354,475	$ 50,198	$ 33,299	$ 2,844	$ 1,877,693
2004						
Acquisition Costs of Properties						
Unproved	$ 129,230	$ 13,490	$ 74	$ -	$ -	$ 142,794
Proved	47,653	4,587	-	-	-	52,240
Subtotal	176,883	18,077	74	-	-	195,034
Exploration Costs	212,324	27,771	35,227	27,818	3,443	306,583
Development Costs [2]	666,443	277,045	48,618	33,133	-	1,025,239
Subtotal	1,055,650	322,893	83,919	60,951	3,443	1,526,856
Deferred Income Tax on Acquired Properties	-	(16,834)	-	-	-	(16,834)
Total	$ 1,055,650	$ 306,059	$ 83,919	$ 60,951	$ 3,443	$ 1,510,022
2003						
Acquisition Costs of Properties						
Unproved	$ 43,890	$ 14,536	$ 172	$ -	$ -	$ 58,598
Proved	18,347	386,532	-	-	-	404,879
Subtotal	62,237	401,068	172	-	-	463,477
Exploration Costs	145,104	15,429	20,517	20,958	4,664	206,672
Development Costs [3] [4]	488,424	149,091	23,140	2,812	-	663,467
Total	$ 695,765	$ 565,588	$ 43,829	$ 23,770	$ 4,664	$ 1,333,616

(1) Includes Asset Retirement Costs of $8 million, $11 million, $0 million and $1 million for the United States, Canada, Trinidad and the United Kingdom, respectively.

(2) Includes Asset Retirement Costs of $6 million, $7 million, $2 million and $2 million for the United States, Canada, Trinidad and the United Kingdom, respectively.

(3) Includes Asset Retirement Costs of $8 million, $4 million, $0 million and $0 million for the United States, Canada, Trinidad and the United Kingdom, respectively.

(4) Asset Retirement Costs for 2003 do not include the cumulative effect of adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	United States	Canada	Trinidad	United Kingdom	Other[(2)]	TOTAL
2005						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 2,571,191	$ 651,349	$ 280,622	$ 103,828	$ -	$ 3,606,990
Other, Net	2,351	(1)	-	398	-	2,748
Total	2,573,542	651,348	280,622	104,226	-	3,609,738
Exploration Costs	112,143	11,512	5,243	4,218	-	133,116
Dry Hole Costs	20,090	24,372	2,571	17,779	-	64,812
Production Costs	412,787	96,296	39,135	10,061	-	558,279
Impairments	70,879	7,053	-	-	-	77,932
Depreciation, Depletion and Amortization	488,621	124,793	24,781	16,063	-	654,258
Income Before Income Taxes	1,469,022	387,322	208,892	56,105	-	2,121,341
Income Tax Provision	527,646	138,365	64,350	22,045	-	752,406
Results of Operations	$ 941,376	$ 248,957	$ 144,542	$ 34,060	$ -	$ 1,368,935
2004						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 1,687,646	$ 448,346	$ 153,377	$ 12,972	$ -	$ 2,302,341
Other, Net	2,128	205	-	-	-	2,333
Total	1,689,774	448,551	153,377	12,972	-	2,304,674
Exploration Costs	71,823	10,264	7,109	4,745	-	93,941
Dry Hole Costs	45,164	11,447	15,851	19,680	-	92,142
Production Costs	294,338	83,527	14,670	1,790	-	394,325
Impairments	68,309	13,221	-	-	-	81,530
Depreciation, Depletion and Amortization	382,718	99,879	20,022	1,784	-	504,403
Income (Loss) Before Income Taxes	827,422	230,213	95,725	(15,027)	-	1,138,333
Income Tax Provision (Benefit)	295,063	75,146	33,953	(7,230)	-	396,932
Results of Operations	$ 532,359	$ 155,067	$ 61,772	$ (7,797)	$ -	$ 741,401
2003						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 1,410,946	$ 309,336	$ 100,112	$ -	$ -	$ 1,820,394
Other, Net	4,613	82	-	-	-	4,695
Total	1,415,559	309,418	100,112	-	-	1,825,089
Exploration Costs	65,885	5,726	3,997	739	11	76,358
Dry Hole Costs	20,706	4,139	7,890	8,421	-	41,156
Production Costs	219,447	58,249	11,363	51	2	289,112
Impairments	81,661	7,473	-	-	(1)	89,133
Depreciation, Depletion and Amortization	359,439	66,334	16,070	-	-	441,843
Income (Loss) Before Income Taxes	668,421	167,497	60,792	(9,211)	(12)	887,487
Income Tax Provision (Benefit)	239,534	61,928	24,661	(3,673)	(5)	322,445
Results of Operations	$ 428,887	$ 105,569	$ 36,131	$ (5,538)	$ (7)	$ 565,042

(1) Excludes gains or losses on mark-to-market financial commodity derivative contracts, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2005.

(2) Other includes other international 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 SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the engineering staff of EOG. The estimates were based on commodity prices at year-end. 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 crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable 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 crude oil and natural gas reserves for the years ended December 31:

	United States	Canada	Trinidad	United Kingdom	TOTAL
2005					
Future cash inflows[1]	$ 29,570,753	$ 11,699,916	$ 4,355,408	$ 447,719	$ 46,073,796
Future production costs	(7,623,688)	(2,824,960)	(617,551)	(50,027)	(11,116,226)
Future development costs	(1,565,491)	(362,191)	(268,306)	(12,482)	(2,208,470)
Future net cash flows before income taxes	20,381,574	8,512,765	3,469,551	385,210	32,749,100
Future income taxes	(6,349,537)	(2,524,804)	(1,311,384)	(146,492)	(10,332,217)
Future net cash flows	14,032,037	5,987,961	2,158,167	238,718	22,416,883
Discount to present value at 10% annual rate	(6,720,718)	(2,966,998)	(994,539)	(32,925)	(10,715,180)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 7,311,319	$ 3,020,963	$ 1,163,628	$ 205,793	$ 11,701,703
2004					
Future cash inflows	$ 17,044,764	$ 7,530,192	$ 3,419,365	$ 312,843	$ 28,307,164
Future production costs	(4,485,711)	(2,436,056)	(486,892)	(77,245)	(7,485,904)
Future development costs	(873,309)	(281,233)	(218,784)	(2,422)	(1,375,748)
Future net cash flows before income taxes	11,685,744	4,812,903	2,713,689	233,176	19,445,512
Future income taxes	(3,583,378)	(1,295,774)	(986,977)	(60,010)	(5,926,139)
Future net cash flows	8,102,366	3,517,129	1,726,712	173,166	13,519,373
Discount to present value at 10% annual rate	(3,795,487)	(1,570,232)	(809,757)	(25,919)	(6,201,395)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 4,306,879	$ 1,946,897	$ 916,955	$ 147,247	$ 7,317,978
2003					
Future cash inflows	$ 14,030,539	$ 6,221,171	$ 2,995,951	$ 320,427	$ 23,568,088
Future production costs	(3,026,650)	(1,289,592)	(449,200)	(47,524)	(4,812,966)
Future development costs	(524,401)	(200,324)	(228,504)	(21,289)	(974,518)
Future net cash flows before income taxes	10,479,488	4,731,255	2,318,247	251,614	17,780,604
Future income taxes	(3,382,125)	(1,376,955)	(786,418)	(96,896)	(5,642,394)
Future net cash flows	7,097,363	3,354,300	1,531,829	154,718	12,138,210
Discount to present value at 10% annual rate	(3,393,605)	(1,610,085)	(778,985)	(41,420)	(5,824,095)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 3,703,758	$ 1,744,215	$ 752,844	$ 113,298	$ 6,314,115

(1) Estimated natural gas prices used to calculate 2005 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $8.46, $8.51, $2.84 and $12.65, respectively. Estimated liquids prices used to calculate 2005 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $55.08, $50.39, $61.16 and $50.46, respectively.

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, 2005:

	United States	Canada	Trinidad	United Kingdom	TOTAL
December 31, 2002	$ 2,774,655	$ 938,966	$ 505,814	$ -	$ 4,219,435
Sales and transfers of oil and gas produced, net of production costs	(1,191,450)	(251,070)	(88,749)	-	(1,531,269)
Net changes in prices and production costs	1,334,817	422,754	294,570	-	2,052,141
Extensions, discoveries, additions and improved recovery, net of related costs	916,653	227,632	93,754	182,581	1,420,620
Development costs incurred	103,200	22,600	23,100	-	148,900
Revisions of estimated development cost	(34,688)	(45,591)	(29,415)	-	(109,694)
Revisions of previous quantity estimates	(35,537)	(34,700)	(65,239)		(135,476)
Accretion of discount	376,431	120,032	73,237	-	569,700
Net change in income taxes	(520,575)	(240,253)	(145,698)	(69,283)	(975,809)
Purchases of reserves in place	94,482	547,011	-	-	641,493
Sales of reserves in place	(63,136)	-	-	-	(63,136)
Changes in timing and other	(51,094)	36,834	91,470	-	77,210
December 31, 2003	3,703,758	1,744,215	752,844	113,298	6,314,115
Sales and transfers of oil and gas produced, net of production costs	(1,393,308)	(364,819)	(138,707)	(11,182)	(1,908,016)
Net changes in prices and production costs	104,059	(148,876)	181,837	(20,213)	116,807
Extensions, discoveries, additions and improved recovery, net of related costs	1,247,934	385,547	8,564	-	1,642,045
Development costs incurred	130,000	88,900	97,000	9,500	325,400
Revisions of estimated development cost	77,986	8,058	(31,237)	5,138	59,945
Revisions of previous quantity estimates	(101,976)	(48,656)	56,372	1,252	(93,008)
Accretion of discount	521,398	224,582	112,510	18,258	876,748
Net change in income taxes	(143,615)	23,315	(124,614)	26,552	(218,362)
Purchases of reserves in place	79,703	15,543	-	-	95,246
Sales of reserves in place	(10,307)	(1,776)	-	-	(12,083)
Changes in timing and other	91,247	20,864	2,386	4,644	119,141
December 31, 2004	4,306,879	1,946,897	916,955	147,247	7,317,978
Sales and transfers of oil and gas produced, net of production costs	(2,158,404)	(555,053)	(241,487)	(93,767)	(3,048,711)
Net changes in prices and production costs	2,854,774	1,780,212	519,166	245,023	5,399,175
Extensions, discoveries, additions and improved recovery, net of related costs	2,694,823	384,295	-	132,470	3,211,588
Development costs incurred	183,800	46,700	25,300	11,100	266,900
Revisions of estimated development cost	(109,358)	(50,061)	(49,083)	(699)	(209,201)
Revisions of previous quantity estimates	(186)	36,687	26,408	(210,930)	(148,021)
Accretion of discount	600,528	242,519	141,383	18,998	1,003,428
Net change in income taxes	(1,341,611)	(513,951)	(148,222)	(81,811)	(2,085,595)
Purchases of reserves in place	135,759	-	-	-	135,759
Sales of reserves in place	(32,817)	-	-	-	(32,817)
Changes in timing and other	177,132	(297,282)	(26,792)	38,162	(108,780)
December 31, 2005	**$ 7,311,319**	**$ 3,020,963**	**$ 1,163,628**	**$ 205,793**	**$ 11,701,703**

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
2005				
Net Operating Revenues	$ 688,156	$ 783,924	$ 934,445	$ 1,213,688
Operating Income	$ 320,095	$ 394,689	$ 522,156	$ 754,875
Income Before Income Taxes	$ 311,603	$ 386,876	$ 518,438	$ 748,220
Income Tax Provision	108,900	137,420	174,677	284,564
Net Income	202,703	249,456	343,761	463,656
Preferred Stock Dividends	1,858	1,858	1,857	1,859
Net Income Available to Common	$ 200,845	$ 247,598	$ 341,904	$ 461,797
Net Income Per Share Available to Common(1)				
Basic	$ 0.85	$ 1.04	$ 1.43	$ 1.92
Diluted	$ 0.83	$ 1.02	$ 1.40	$ 1.88
Average Number of Common Shares				
Basic	237,293	238,252	239,344	240,427
Diluted	242,114	243,414	244,900	245,463
2004				
Net Operating Revenues	$ 464,320	$ 519,021	$ 594,230	$ 693,654
Operating Income	$ 171,436	$ 226,736	$ 274,500	$ 306,523
Income Before Income Taxes	$ 152,024	$ 212,745	$ 262,343	$ 298,900
Income Tax Provision	51,171	67,808	90,033	92,145
Net Income	100,853	144,937	172,310	206,755
Preferred Stock Dividends	2,758	2,758	2,758	2,618
Net Income Available to Common	$ 98,095	$ 142,179	$ 169,552	$ 204,137
Net Income Per Share Available to Common(1) (2)				
Basic	$ 0.42	$ 0.61	$ 0.72	$ 0.86
Diluted	$ 0.42	$ 0.60	$ 0.71	$ 0.85
Average Number of Common Shares(2)				
Basic	231,289	232,776	234,822	236,140
Diluted	235,242	237,417	239,354	241,113

(1) The sum of quarterly net income per share available to common may not agree with total year net income per share available to common as each quarterly computation is based on the weighted average of common shares outstanding.
(2) Restated for the two-for-one stock split effective March 1, 2005.

Schedule II

EOG RESOURCES, INC.

VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2005, 2004 and 2003
(In Thousands)

Description	Column B Balance at Beginning of Year	Column C Additions Charged to Costs and Expenses	Column D Deductions From Reserves	Column E Balance at End of Year
2005				
Allowance deducted from Accounts Receivable	$ 20,619	$ 1,679	$ 492	$ 21,806
2004				
Allowance deducted from Accounts Receivable	$ 20,748	$ 45	$ 174	$ 20,619
2003				
Allowance deducted from Accounts Receivable	$ 20,287	$ 506	$ 45	$ 20,748

EXHIBITS

Exhibits not incorporated herein by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated herein by reference to EOG's Form S-1 Registration Statement, Registration No. 33-30678, filed on August 24, 1989 (Form S-1), or as otherwise indicated.

Exhibit Number		Description
3.1(a)	-	Restated Certificate of Incorporation (Exhibit 3.1 to Form S-1).
3.1(b)	-	Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 4.1(b) to Form S-8 Registration Statement No. 33-52201, filed February 8, 1994).
3.1(c)	-	Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 4.1(c) to Form S-8 Registration Statement 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 Form S-3 Registration Statement 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 Form S-3 Registration Statement No. 333-44785, filed January 23, 1998).
3.1(f)	-	Certificate of Ownership and Merger, dated August 26, 1999 (Exhibit 3.1(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
3.1(g)	-	Certificate of Designations of Series E Junior Participating Preferred Stock, dated February 14, 2000 (Exhibit 2 to Form 8-A Registration Statement, filed February 18, 2000).
3.1(h)	-	Certificate of Designation, Preferences and Rights of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, dated July 19, 2000 (Exhibit 3.1(h) to EOG's Registration Statement on Form S-3 Registration Statement No. 333-46858, filed September 28, 2000).
3.1(i)	-	Certificate of Elimination of the Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, dated September 15, 2000 (Exhibit 3.1(j) to EOG's Registration Statement on Form S-3 Registration Statement No. 333-46858, filed September 28, 2000).
3.1(j)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series C, dated September 15, 2000 (Exhibit 3.1(k) to EOG's Registration Statement on Form S-3 Registration Statement No. 333-46858, filed September 28, 2000).
3.1(k)	-	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).
3.1(l)	-	Certificate of Amendment to 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).
3.2	-	By-laws, dated August 23, 1989, as amended and restated effective as of February 24, 2004 (Exhibit 3.2 to EOG's Annual Report on Form 10-K for the year ended December 31, 2003).
4.1(a)	-	Specimen of Certificate evidencing the Common Stock (Exhibit 3.3 to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
4.1(b)	-	Specimen of Certificate Evidencing Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B (Exhibit 4.3(g) to EOG's Registration Statement on Form S-4 Registration Statement No. 333-36056, filed June 7, 2000).

Exhibit **Number**		**Description**
4.2	-	Rights Agreement, dated as of February 14, 2000, between EOG and First Chicago Trust Company of New York, which includes the form of Rights Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Shares as Exhibit C (Exhibit 1 to EOG's Registration Statement on Form 8-A, filed February 18, 2000).
4.3	-	Form of Rights Certificate (Exhibit 3 to EOG's Registration Statement on Form 8-A, filed February 18, 2000).
4.4	-	Indenture dated as of September 1, 1991, between EOG and Chase Bank of Texas National Association (formerly, Texas Commerce Bank National Association) (Exhibit 4(a) to EOG's Registration Statement on Form S-3 Registration Statement No. 33-42640, filed September 6, 1991).
4.5	-	Indenture dated as of __________, 2000, between EOG and The Bank of New York (Exhibit 4.6 to EOG's Registration Statement on Form S-3 Registration Statement No. 333-46858, filed September 28, 2000).
4.6	-	Amendment, dated as of December 13, 2001, to the Rights Agreement, dated as of February 14, 2000, between EOG and First Chicago Trust Company of New York, as rights agent (Exhibit 2 to Amendment No. 1 to EOG's Registration Statement on Form 8-A/A filed December 14, 2001).
4.7	-	Letter dated December 13, 2001, from First Chicago Trust Company of New York to EOG resigning as rights agent effective January 12, 2002 (Exhibit 3 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A filed February 7, 2002).
4.8	-	Amendment, dated as of December 20, 2001, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and First Chicago Trust Company of New York, as rights agent (Exhibit 4 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A filed February 7, 2002).
4.9	-	Letter dated December 20, 2001, from EOG Resources, Inc. to EquiServe Trust Company, N.A. appointing EquiServe Trust Company, N.A. as successor rights agent (Exhibit 5 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A filed February 7, 2002).
4.10	-	Amendment, dated as of April 11, 2002, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed April 12, 2002).
4.11	-	Amendment, dated as of December 10, 2002, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed December 11, 2002).
4.12	-	Amendment, dated as of February 24, 2005, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.12 to EOG's Annual Report on Form 10-K for the year ended December 31, 2004).
4.13	-	Amendment, dated as of June 15, 2005, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.1(a)	-	Amended and Restated 1994 Stock Plan (Exhibit 4.3 to Form S-8 Registration Statement No. 33-58103, filed March 15, 1995).
10.1(b)	-	Amendment to Amended and Restated 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).
10.1(c)	-	Amendment to Amended and Restated 1994 Stock Plan, dated effective as of December 10, 1996 (Exhibit 4.3(a) to Form S-8 Registration Statement No. 333-20841, filed January 31, 1997).

Exhibit Number		Description
10.1(d)	-	Third Amendment to Amended and Restated 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).
10.1(e)	-	Fourth Amendment to Amended and Restated 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).
10.1(f)	-	Fifth Amendment to Amended and Restated 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).
10.1(g)	-	Sixth Amendment to Amended and Restated 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).
*10.1(h)	-	Seventh Amendment to Amended and Restated 1994 Stock Plan, dated effective as of December 30, 2005.
10.2(a)	-	Amended and Restated 1993 Nonemployee Directors Stock Option Plan (Exhibit A to EOG's Proxy Statement, dated March 28, 2002, with respect to EOG's Annual Meeting of Shareholders).
*10.2(b)	-	First Amendment to Amended and Restated 1993 Nonemployee Directors Stock Option Plan, dated effective as of December 30, 2005.
10.3(a)	-	Amended and Restated 1992 Stock Plan (Exhibit B to EOG's Proxy Statement, dated March 29, 2004, with respect to EOG's Annual Meeting of Shareholders).
*10.3(b)	-	First Amendment to Amended and Restated 1992 Stock Plan, dated effective as of December 30, 2005.
10.4(a)	-	Amended and Restated 1996 Deferral Plan (Exhibit 4.4 to Form S-8 Registration Statement No. 333-84014, filed March 8, 2002).
10.4(b)	-	First Amendment to Amended and Restated 1996 Deferral Plan, effective as of September 10, 2002 (Exhibit 10.9(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2002).
10.5(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).
10.5(b)	-	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(a)	-	Executive Employment Agreement between EOG and Edmund P. Segner, III, effective as of June 15, 2005 (Exhibit 99.2 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.6(b)	-	Amended and Restated Change of Control Agreement between EOG and Edmund P. Segner, III, effective as of June 15, 2005 (Exhibit 99.7 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.7(a)	-	Executive Employment Agreement between EOG and Barry Hunsaker, Jr., effective as of June 15, 2005 (Exhibit 99.5 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.7(b)	-	Amended and Restated Change of Control Agreement between EOG and Barry Hunsaker, Jr., effective as of June 15, 2005 (Exhibit 99.10 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.8(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).
10.8(b)	-	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).

Exhibit Number		Description
10.9(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).
10.9(b)	-	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).
10.10(a)	-	Amended and Restated Change of Control Severance Plan, effective as of June 15, 2005 (Exhibit 99.12 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.11	-	Employee Stock Purchase Plan (Exhibit 4.4 to Form S-8 Registration Statement No. 333-62256, filed June 4, 2001).
10.12	-	Amended and Restated Savings Plan (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005.
10.13	-	Executive Officer Annual Bonus Plan (Exhibit C to EOG's Proxy Statement, dated March 30, 2001, with respect to EOG's Annual Meeting of Shareholders).
10.15	-	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).
10.16	-	Revolving Credit Agreement, dated June 28, 2005, among EOG Resources, Inc., JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
10.17	-	Senior Term Loan Agreement, dated October 28, 2005, among EOG Resources, Inc., as Parent Guarantor, EOGI International Company, as Borrower, The Bank of Nova Scotia, as Administrative Agent, and the financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005).
*12	-	Computation of Ratio of Earnings to Fixed Charges and to Combined Fixed Charges and Preferred Stock Dividends.
*21	-	List of subsidiaries.
*23.1	-	Consent of DeGolyer and MacNaughton.
*23.2	-	Opinion of DeGolyer and MacNaughton dated January 30, 2006.
*23.3	-	Consent of Deloitte & Touche LLP.
*24	-	Powers of Attorney.
*31.1	-	Section 302 Certification of Annual Report of Chief Executive Officer.
*31.2	-	Section 302 Certification of Annual Report of Principal Financial Officer.
*32.1	-	Section 906 Certification of Annual Report of Chief Executive Officer.
*32.2	-	Section 906 Certification of Annual Report of Principal Financial Officer.

SIGNATURES

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

EOG RESOURCES, INC.
(Registrant)

Date: February 22, 2006

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of registrant and in the capacities with EOG Resources, Inc. indicated and on the 22nd day of February, 2006.

Signature	Title
/s/ MARK G. PAPA (Mark G. Papa)	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)
/s/ EDMUND P. SEGNER, III (Edmund P. Segner, III)	President and Chief of Staff and Director (Principal Financial Officer)
/s/ TIMOTHY K. DRIGGERS (Timothy K. Driggers)	Vice President and Chief Accounting Officer (Principal Accounting Officer)
*GEORGE A. ALCORN (George A. Alcorn)	Director
*CHARLES R. CRISP (Charles R. Crisp)	Director
*WILLIAM D. STEVENS (William D. Stevens)	Director
*H. LEIGHTON STEWARD (H. Leighton Steward)	Director
*DONALD F. TEXTOR (Donald F. Textor)	Director
*FRANK G. WISNER (Frank G. Wisner)	Director

*By /s/ PATRICIA L. EDWARDS
(Patricia L. Edwards)
(Attorney-in-fact for persons indicated)