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, 2004

☐ **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, $0.01 par value	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 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 an accelerated filer (as defined in Rule 12b-2 of the 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 15, 2005 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 15, 2005: $9,795,349,791 and as of June 30, 2004: $7,022,029,810.

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 15, 2005, Shares Outstanding: 119,208,346.

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 3, 2005 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2004 (Proxy Statement) - Part III.

TABLE OF CONTENTS

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, 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 under "Exploration and Production" below. EOG's website address is http://www.eogresources.com. 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).

At December 31, 2004, EOG's total estimated net proved reserves were 5,647 billion cubic feet equivalent (Bcfe), of which 5,047 billion cubic feet (Bcf) were natural gas reserves and 100 million barrels (MMBbl), or 600 Bcfe, were crude oil, condensate and natural gas liquids reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 50% of EOG's reserves (on a natural gas equivalent basis) were located in the United States, 25% in Trinidad, 24% in Canada and 1% in the United Kingdom North Sea. As of December 31, 2004, EOG employed approximately 1,250 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 exploitation and exploration. EOG focuses on the cost-effective utilization of advances in technology associated with the gathering, processing and interpretation of three-dimensional seismic data, the development of reservoir simulation models, the use of new and/or improved drill bits, mud motors and mud additives, 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, 2004, 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. A substantial portion of EOG's United States and Canada natural gas reserves are in long-lived fields with well-established production histories. EOG believes that opportunities exist to increase production in and around many of these fields through continued development and application of new technology. EOG will also continue an active exploration program, designed to extend fields and add new trends to its broad portfolio of United States and Canada plays. The following is a summary of significant developments during 2004 and certain 2005 plans for EOG's United States and Canada operations.

United States. During 2004, EOG opened a new office in Fort Worth, Texas to expand EOG's drilling success in the Barnett Shale play of the Fort Worth Basin. EOG made significant gas discoveries in the non-core portion of the trend located south and west of the city of Fort Worth, drilling 27 net horizontal Barnett wells in 2004. As a result of this success, EOG rapidly expanded its leasehold position and ended 2004 with approximately 400,000 net acres in the Barnett play. During December 2004, EOG reached 30 million cubic feet equivalent per day (MMcfed) net production from the Fort Worth Basin. EOG plans to drill 90 Barnett horizontal wells and will continue to add acreage in the Barnett trend during 2005.

In the Permian Basin, EOG maintained successful horizontal programs in the Devonian play of West Texas and in the Bone Spring play of Southeast New Mexico. Improvements in technology continued to yield increases in production rates and reserves, when compared to completions of previous years. EOG drilled 46 net wells in the Permian Basin in 2004, and net production averaged 97 million cubic feet per day (MMcfd) of natural gas and 8.3 thousand barrels per day (MBbld) of crude oil, condensate and natural gas liquids. EOG has assembled a substantial acreage position of over 130,000 net acres in a number of new plays in this area, many of which will be tested during 2005.

EOG continued to intensify its activities in the Rocky Mountain area during 2004. EOG has ramped up operations in its traditional plays, drilling 48 net wells in the Chapita/Natural Buttes area of the Uinta Basin, Utah, and 40 net wells in each area of Wyoming's Green River Basin - the Big Piney area and the LaBarge Platform/Moxa Arch area. EOG also drilled 16 net wells in the Bakken horizontal play of the Williston Basin in Montana. The net daily production from the Rocky Mountain area averaged 129 MMcfd of natural gas and 6.3 MBbld of crude oil, condensate and natural gas liquids. EOG expects to further increase drilling activity in 2005 in both the Uinta Basin of Utah and the Green River Basin of Wyoming, and also continue exploration drilling in other Rocky Mountain basins.

In the Mid-Continent area, EOG drilled 150 net wells in its two core areas in 2004 - the Hugoton-Deep play in the Oklahoma Panhandle and the Cleveland Horizontal play in the Texas Panhandle. The net average daily production was 70 MMcfd of natural gas and 1.9 MBbld of crude oil and condensate. EOG expanded its Cleveland position over the last year to 110,000 net acres. EOG has drilled 70 net Cleveland horizontal wells during the past few years and expects to drill another 50 net wells in 2005. EOG has also obtained the rights on 40,000 of these Cleveland acres to drill for high potential Morrow accumulations. EOG expects its Hugoton Deep program to continue at a level comparable to 2004. In addition to these two core areas, EOG will continue active exploration programs throughout Oklahoma, Kansas and the Texas Panhandle.

The Upper Gulf Coast continues to be a significant producing and exploration area for EOG. New operating trends have been added in East Texas and Louisiana through exploration and property trades. Most notably, a significant Lower Cotton Valley field discovery was made in North Louisiana at the Driscoll Mountain field where a development of five net wells is planned for 2005. EOG drilled 53 net wells in the Upper Gulf Coast area during 2004 and averaged net production of 94 MMcfd of natural gas and 2.9 MBbld of crude oil, condensate and natural gas liquids. In the Sligo Field, EOG has drilled 4.5 net wells since the completion of a property trade in mid-2003, increasing net natural gas production from 2.5 MMcfd to 8.7 MMcfd. EOG is anticipating running two to three rigs full time in the Sligo Field throughout 2005. 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 2005.

EOG continues to have success in South Texas where EOG drilled or participated in 76 net wells in 2004. The area averaged net production of 169 MMcfd of natural gas and 4.7 MBbld of crude oil, condensate and natural gas liquids. The activity was mainly focused in Webb, Zapata, Nueces, Lavaca and Duval Counties. EOG executed successful drilling programs in the Lobo, Roleta, Frio, Wilcox and Olmos 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 in 2004 to sustain drilling through 2005 and beyond.

In 2004, EOG drilled 70 net wells in the Appalachian area and net production averaged 23 MMcfd of natural gas. EOG continues to pursue the Trenton Black River play in New York, and has begun to develop other intermediate depth plays in West Virginia and New York in Mississippian and Ordovician age reservoirs. EOG expects to drill over 100 net wells in 2005 in this area.

In the Gulf of Mexico, four shelf fields (South Timbalier 156, Eugene Island 135, High Island 206 and Matagorda Island 623) accounted for over 60% of EOG's 2004 net production. During 2004, total net production averaged 44 MMcfd of natural gas and 1.7 MBbld of crude oil, condensate and natural gas liquids. The Matagorda Island 685 field, a 2003 discovery, commenced sales in July 2004. EOG has a 67.5% working interest in the field, which was producing 9 MMcfed, net, of natural gas and condensate at year-end. In 2004, EOG drilled or participated in nine gross wells; EOG plans a similar level of activity on the Gulf of Mexico shelf in 2005.

At December 31, 2004, EOG held approximately 2,609,400 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 2004, EOGRC was again successful with its shallow natural gas strategy in Western Canada, drilling a record of 1,254 net wells and increasing its production and reserve base. EOGRC's net production during 2004 averaged 212 MMcfd of natural gas and 3.5 MBbld of crude oil, condensate and natural gas liquids. Fourth quarter 2004 net production of 234 MMcfd of natural gas and 4.0 MBbld of crude oil, condensate and natural gas liquids was a 20% increase over fourth quarter 2003 net production of 195 MMcfd of natural gas and 3.4 MBbld of crude oil, condensate and natural gas liquids, which included production from properties acquired in the fourth quarter of 2003. Key producing areas in the Western Canadian Sedimentary Basin are the Southeast Alberta/Southwest Saskatchewan shallow natural gas trend as well as the Drumheller, Twining and Grande Prairie/Wapiti areas of central Alberta. EOGRC expects a similar level of shallow natural gas drilling in 2005 on its expanded Southeast Alberta platform, including the development of Horseshoe Canyon dry coalbed methane at Twining. EOG also plans to participate in several higher impact exploratory tests in Alberta and the Northwest Territories during 2005.

At December 31, 2004, EOG held approximately 1,427,800 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 a 95% working interest, subject to a 5% overriding royalty interest, in the South East Coast Consortium (SECC) Block offshore Trinidad, encompassing three undeveloped fields - the Kiskadee, Ibis and Oilbird fields. The Parula field was discovered in 2002 and commenced production in 2004. The Kiskadee and Ibis fields have been developed and are being produced. EOG is currently developing the Oilbird field and expects first production in early 2007. The term of the license covering the SECC Block expires in December 2029. Effective February 3, 2005, EOG's working interest was reduced to 80% due to conversion of the overriding royalty interest. During 2004, average net production from the SECC Block was 116 MMcfd of natural gas and 2.2 MBbld of crude oil and condensate.

In the fourth quarter of 2004, EOG, through EOGRT and its SECC partners, signed a farm in agreement with BP Trinidad and Tobago LLC covering the Deep Ibis prospect on the SECC Block. BP will pay the entire cost for drilling the well, which is anticipated to spud in late 2005. EOG will retain a 50.6% 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 where EOG holds a 100% working interest. The Osprey field was discovered in 1998 and commenced production in 2002. During 2004, average net production from the U(a) Block was 70 MMcfd of natural gas and 1.4 MBbld of condensate.

Existing surplus processing and transportation capacity at the Pelican field facilities owned and operated by a subsidiary of EOGRT's partners in the SECC Block is being used to process and transport much of EOG's natural gas production and all of its condensate and crude oil production from the SECC and U(a) Blocks. Condensate and crude oil 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" Block which is adjacent to the SECC Block. EOG holds a 100% working interest in the Lower Reverse "L" 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.

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.

At December 31, 2004, EOG held approximately 191,600 net undeveloped acres in Trinidad.

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, which was scheduled to expire in 2008, natural gas was delivered to NGC for resale to Trinidad local markets. During 2004, EOG delivered net average production of 116 MMcfd of natural gas under this agreement. In February 2005, the parties to the agreement executed an amended and restated take-or-pay contract to replace the existing agreement. The new agreement, 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. The expiration date of the new agreement is December 31, 2018.

- 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 2004, 48 MMcfd of natural gas delivered to NGC was net to EOG. CNCL commenced production in June 2002 and currently produces approximately 1,850 metric tons of ammonia daily. EOGRT owns a 12% equity interest in CNCL. The other shareholders in CNCL are Ferrostaal AG, Clico Energy Company Limited, KBRDC CNC (Cayman) Ltd. and Koch CNC (Nevis) LLC. At December 31, 2004, EOGRT's investment in CNCL was $15 million. At December 31, 2004, CNCL had a long-term debt balance of $203 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 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 2004, EOG recognized equity income of $5 million and received cash dividends of $5 million from CNCL.

- Under a fifteen-year take-or-pay contract, which expires in 2019, EOG supplies approximately 60 MMcfd, gross, of natural gas to NGC. During 2004, production under the contract averaged approximately 22 MMcfd of natural gas net to EOG. This gas is being resold by NGC to an anhydrous ammonia plant owned by Nitrogen (2000) Unlimited (N2000) and located in Point Lisas, Trinidad. Construction of the plant was completed in June 2004 at a total cost of $320 million and ammonia production commenced in August 2004. N2000 currently produces approximately 1,950 metric tons of ammonia daily. EOG's subsidiary, EOG Resources NITRO2000 Ltd. (EOGNitro2000), owned a 23% equity interest in N2000 at December 31, 2004. The other shareholders in N2000 are FS Petrochemicals (St. Kitts) Limited, CE Limited, KBRDC Nitrogen 2000 (St. Lucia) Ltd. and Koch N2000 (Nevis) LLC. At December 31, 2003, EOGNitro2000's equity interest and investment in N2000 was 27% and $20 million, respectively. In February 2004, a portion of EOGNitro2000's shareholdings was sold to one of the other shareholders. The sale did not result in any gain or loss. At December 31, 2004, EOGNitro2000's investment in N2000 was $26 million. At December 31, 2004, N2000 had a long-term debt balance of $228 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 $7 million of which is to be provided by the immediate parent company of EOGNitro2000. The Shareholders' Agreement 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 2004, EOG recognized equity income of $6 million from N2000.

  In February 2005, a portion of EOGNitro2000's shareholdings was sold to a subsidiary of one of the other shareholders. The sale resulted in a pre-tax gain of approximately $2 million. EOGNitro2000's equity interest is now 10%.

- Under a natural gas contract signed in January 2004, EOG will ultimately supply 94 MMcfd (60 MMcfd, net, based on current price and operating assumptions) of natural gas to NGC for the initial four years of the contract term and 122 MMcfd (80 MMcfd, net, based on current price and operating assumptions) for the remaining term of the contract (11 years). This natural gas is being resold by NGC to a methanol plant located in Point Lisas, Trinidad. The plant is presently under construction and is expected to start up in mid-2005. EOG has no equity investment in this plant.

- Lastly, 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 (20 MMcfd, net) of natural gas for use in a LNG plant in Point Fortin, Trinidad. The plant is presently under construction and is expected to start up in mid-2006. EOG has no equity investment in this LNG plant.

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. The first commercial well, the 49/16-14Z, in the Valkyrie field, was drilled in the Southern Gas Basin and temporarily suspended in February 2003. The well encountered 300 feet of net pay sands in the Rotliegendes formation, with gross estimated natural gas reserves of 106 Bcf, or 26 Bcf, net to EOGUK. EOGUK and its partners drilled a development well 49/16-VB from the Vampire platform in 2004 and production commenced in the third quarter of 2004. EOG delivered net average production of approximately 7 MMcfd from the Valkyrie field in 2004.

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. EOGUK drilled the successful exploratory well 53/2-11 in November 2003. The well encountered approximately 198 feet of net pay sands in the Rotliegendes formation, with gross estimated natural gas reserves of 109 Bcf, or 33 Bcf, net to EOGUK. This discovery, named the Arthur field, commenced production in January 2005.

In the first quarter of 2004, EOGUK completed the drilling of an exploration well, 49/2a-5Z. The well was determined to be non-commercial.

In the second half of 2004, EOGUK drilled its first operated well, 49/21-9Z, in the Viper prospect. The well was abandoned as a dry hole.

At December 31, 2004, EOG held approximately 75,700 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. Wellhead natural gas volumes from Trinidad in 2004 were sold under either a contract with a fixed price schedule with annual escalations, or a contract that is price dependent on Caribbean ammonia index prices. Beginning in 2005, wellhead natural gas volumes from Trinidad will be sold under contracts with prices which are either wholly or partially dependent on Caribbean ammonia index prices and/or methanol 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 2004, sales to an integrated oil and gas company with investment grade credit ratings accounted for 12% 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, 2004.

	2004	2003	2002
Natural Gas Volumes (MMcf per day)			
United States	631	638	635
Canada	212	165	154
Trinidad	186	152	135
United Kingdom	7	-	-
Total	**1,036**	**955**	**924**
Crude Oil and Condensate Volumes (MBbl per day)			
United States	21.1	18.5	18.8
Canada	2.7	2.3	2.1
Trinidad	3.6	2.4	2.4
Total	**27.4**	**23.2**	**23.3**
Natural Gas Liquids Volumes (MBbl per day)			
United States	4.8	3.2	2.9
Canada	0.8	0.6	0.8
Total	**5.6**	**3.8**	**3.7**
Natural Gas Equivalent Volumes (MMcfe per day)			
United States	786	768	765
Canada	233	183	171
Trinidad	207	166	150
United Kingdom	7	-	-
Total	**1,233**	**1,117**	**1,086**
Average Natural Gas Prices ($/Mcf)			
United States	$ 5.72	$ 5.06	$ 2.89
Canada	5.22	4.66	2.67
Trinidad	1.51	1.35	1.20
United Kingdom	5.14	-	-
Composite	**4.86**	**4.40**	**2.60**
Average Crude Oil and Condensate Prices ($/Bbl)			
United States	$ 40.73	$ 30.24	$ 24.79
Canada	37.68	28.54	23.62
Trinidad	39.12	28.88	23.58
Composite	**40.22**	**29.92**	**24.56**
Average Natural Gas Liquids Prices ($/Bbl)			
United States	$ 27.79	$ 21.53	$ 14.76
Canada	23.23	19.13	11.17
Composite	**27.13**	**21.13**	**14.05**

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. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability.

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 concerning the above and other matters. 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. In early 2005, the MMS is expected to publish a further revision to its gas valuation rule. The 2005 gas rule revision will clarify the deductibility of transportation costs and adopt the 2004 oil valuation rule's cost of capital approach described below. The revisions are not expected to reflect any major changes. 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 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 NYMEX 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 attenuate 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 pursued 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 project 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 period. Although the Canadian government has not yet provided significant guidance on how it intends to meet these reduction targets, the energy industry has been identified as one of the areas that will be affected. 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 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 32% decrease in the average wellhead natural gas price for production in the United States and Canada received by EOG from 2001 to 2002, an increase of 75% from 2002 to 2003, and an increase of 12% from 2003 to 2004. Wellhead natural gas volumes from Trinidad in 2004 were sold under either a contract with a fixed price schedule with annual escalations, or a contract that is price dependent on Caribbean ammonia index prices. Beginning in 2005, wellhead natural gas volumes from Trinidad will be sold under contracts with prices which are either wholly or partially dependent on Caribbean ammonia index prices and/or methanol 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, and ammonia prices in the future.

Assuming a totally unhedged position for 2005, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2005 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 $21 million for net income and operating cash flow. EOG is not impacted as significantly by changing crude oil prices. EOG's price sensitivity for each $1.00 per barrel change in average wellhead crude oil price is approximately $6.5 million for net income and operating cash flow. Summarized below and in Note 11 to the Consolidated Financial Statements is information regarding EOG's 2005 natural gas hedge position.

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 derivative financial instruments, primarily price swaps and collars, as the means to manage this price risk. In addition to these 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 various 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 these various 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 2005 natural gas financial collar contracts at February 25, 2005, 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 swap contracts that cover periods beyond March 2005. Moreover, EOG has not entered into any additional natural gas financial collar contracts or natural gas or crude oil financial price swap contracts since December 31, 2004. EOG accounts for these collar and swap contracts using mark-to-market accounting.

Natural Gas Financial Collar Contracts

		Floor Price		Ceiling Price		
2005	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average ($/MMBtu)	Settlement Price ($/MMBtu)
Jan(1)	75,000	$ 7.65 - 8.00	$ 7.77	$ 8.90 - 9.50	$ 9.10	$ 6.35
Feb(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32	6.36
Mar(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32	6.24

(1) Notional volumes of 25,000 MMBtud of the January 2005 collar contracts were purchased at a premium of $0.10 per MMBtu.
(2) The collar contracts for February 2005 and March 2005 were purchased at a premium of $0.10 per MMBtu.

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.

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 $.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. On March 1, 2005, EOG will effect 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 stock split will have 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 (Preferred Share) for $90, once the Rights become exercisable. This portion of a Preferred 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 Preferred Share (i) will not be redeemable; (ii) will entitle holders to quarterly dividend payments of $.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 the 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).

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 $.01 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 $.01 per Right. The redemption price will be adjusted if EOG has a 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 Series E Junior Participating Preferred Stock with the rights and preferences described above. On February 24, 2005, EOG's Board of Directors increased the authorized shares of Series E Junior Participating Preferred Stock to 3,000,000 as a result of the two-for-one stock split mentioned above. Currently, there are no shares of the Series E Junior Participating Preferred Stock 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.

On July 25, 2000, EOG's Board of Directors authorized 500 shares of Flexible Money Market Cumulative Preferred Stock, Series D, with a liquidation preference of $100,000 per share (the "Series D"). Dividends were payable on the shares only if declared by EOG's Board of Directors and were cumulative. The initial dividend rate on the shares was 6.84% until December 15, 2004. Through December 15, 2004, dividends were payable, if declared, on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. On December 15, 2004, EOG redeemed all 500 outstanding shares of the Series D at a redemption price of $100,000 per share plus accumulated and unpaid dividends for a total of $50 million. On February 24, 2005, EOG filed a Certificate of Elimination with the Secretary of State of the State of Delaware to eliminate the Series D 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	58	Chairman of the Board and Chief Executive Officer; Director
Edmund P. Segner, III	51	President and Chief of Staff; Director
Loren M. Leiker	51	Executive Vice President, Exploration and Development
Gary L. Thomas	55	Executive Vice President, Operations
Barry Hunsaker, Jr.	54	Senior Vice President and General Counsel
Timothy K. Driggers	43	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.

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 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, 2004. 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	569,233	329,004	1,577,834	962,188	2,147,067	1,291,192
Wyoming	195,141	135,009	421,631	312,169	616,772	447,178
Oklahoma	259,347	146,278	204,026	142,695	463,373	288,973
Pennsylvania	81,793	70,676	185,755	176,521	267,548	247,197
New Mexico	101,059	66,638	259,581	161,421	360,640	228,059
Utah	80,119	56,519	224,266	146,682	304,385	203,201
Offshore Gulf of Mexico	208,545	76,184	189,738	95,975	398,283	172,159
Montana	130,367	6,503	153,052	116,966	283,419	123,469
Nevada	-	-	102,386	102,386	102,386	102,386
West Virginia	76,271	68,739	56,120	27,936	132,391	96,675
New York	-	-	100,494	89,142	100,494	89,142
Ohio	61,916	58,504	22,560	22,628	84,476	81,132
California	5,146	2,425	72,199	67,651	77,345	70,076
Colorado	22,509	1,309	76,720	53,922	99,229	55,231
Virginia	-	-	38,707	38,707	38,707	38,707
North Dakota	3,947	1,414	49,329	33,830	53,276	35,244
Louisiana	19,663	12,585	32,433	22,440	52,096	35,025
Kansas	10,658	9,409	19,911	17,227	30,569	26,636
Mississippi	25,819	14,295	43,680	12,298	69,499	26,593
Michigan	-	-	8,817	6,242	8,817	6,242
Arkansas	3,992	1,115	765	228	4,757	1,343
Alabama	-	-	258	193	258	193
Total United States	1,855,525	1,056,606	3,840,262	2,609,447	5,695,787	3,666,053
Canada						
Alberta	1,348,898	1,074,648	658,939	618,289	2,007,837	1,692,937
Saskatchewan	372,196	341,924	191,318	137,534	563,514	479,458
Nova Scotia	-	-	749,213	374,607	749,213	374,607
Northwest Territories	699	184	828,898	181,154	829,597	181,338
British Columbia	8,323	1,920	75,181	67,217	83,504	69,137
Manitoba	17,300	16,198	48,968	48,968	66,268	65,166
New Brunswick	219	33	-	-	219	33
Total Canada	1,747,635	1,434,907	2,552,517	1,427,769	4,300,152	2,862,676
Trinidad	44,557	43,237	237,475	191,620	282,032	234,857
United Kingdom	7,159	2,078	184,373	75,703	191,532	77,781
Total	3,654,876	2,536,828	6,814,627	4,304,539	10,469,503	6,841,367

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, 2004. Gross natural gas and crude oil wells include 528 with multiple completions.

	Productive Wells	
	Gross	**Net**
Natural Gas	17,701	14,765
Crude Oil	1,704	1,145
Total	19,405	15,910

Drilling and Acquisition Activities. During the years ended December 31, 2004, 2003 and 2002, EOG expended approximately $1,510 million, $1,333 million and $836 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:

	2004		2003		2002	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development Wells Completed						
United States and Canada						
Gas	1,839	1,623.34	1,586	1,439.99	1,465	1,204.93
Oil	92	79.31	89	78.98	88	64.27
Dry	104	86.86	89	78.02	84	74.88
Total	2,035	1,789.51	1,764	1,596.99	1,637	1,344.08
Outside United States and Canada						
Gas	5	4.10	-	-	-	-
Oil	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	5	4.10	-	-	-	-
Total Development	2,040	1,793.61	1,764	1,596.99	1,637	1,344.08
Exploratory Wells Completed						
United States and Canada						
Gas	49	44.19	46	28.91	22	17.97
Oil	5	3.00	5	4.22	4	3.00
Dry	41	29.21	39	29.22	22	17.87
Total	95	76.40	90	62.35	48	38.84
Outside United States and Canada						
Gas	1	0.95	2	0.55	1	0.95
Oil	-	-	-	-	-	-
Dry	3	1.93	2	1.50	-	-
Total	4	2.88	4	2.05	1	0.95
Total Exploratory	99	79.28	94	64.40	49	39.79
Total	2,139	1,872.89	1,858	1,661.39	1,686	1,383.87
Wells in Progress at end of period	63	49.38	90	79.49	50	42.93
Total	2,202	1,922.27	1,948	1,740.88	1,736	1,426.80
Wells Acquired*						
Gas	249	151.71	1,274	1,079.02	664	374.06
Oil	8	7.30	108	68.03	7	4.21
Total	257	159.01	1,382	1,147.05	671	378.27

* 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 2004.

PART II

ITEM 5. ***Market for Registrant's Common Equity and Related Shareholder Matters***

The following table sets forth, for the periods indicated, the high and low sales prices 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. The information shown in the following table is not adjusted for the stock split discussed below.

	Price Range High	Price Range Low	Dividend Declared
2004			
First Quarter	$ 47.45	$ 42.45	$ 0.06
Second Quarter	63.69	45.32	0.06
Third Quarter	66.87	55.20	0.06
Fourth Quarter	76.50	64.15	0.06
2003			
First Quarter	$ 42.83	$ 35.70	$ 0.04
Second Quarter	45.56	36.56	0.05
Third Quarter	42.87	37.70	0.05
Fourth Quarter	47.52	40.85	0.05

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.

As of February 15, 2005, there were approximately 275 record holders of EOG's common stock, including individual participants in security position listings. There are an estimated 77,000 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, 2004 - October 31, 2004	525	$67.18	-	6,386,200
November 1, 2004 - November 30, 2004	90,721	65.57	-	6,386,200
December 1, 2004 - December 31, 2004	794	73.45	-	6,386,200
Total	92,040	$65.65	-	

(1) The quarterly total number of shares of 92,040 consists solely of 65,469 shares (117,743 shares for the full year 2004) that were returned to EOG in payment of the exercise price of employee stock options and 26,571 shares (42,059 shares for the full year 2004) 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 of Directors authorized the repurchase of up to 10,000,000 shares of EOG's common stock. During 2004, EOG did not repurchase any shares under the Board of Directors authorized repurchase program.

ITEM 6. ***Selected Financial Data***

(In Thousands, Except Per Share Amounts)

Year Ended December 31	**2004**	**2003**	**2002**	**2001**	**2000**
Statement of Income Data:					
Net Operating Revenues	$2,271,225	$1,744,675	$1,094,682	$1,655,722	$1,484,356
Operating Income	979,195	697,314	180,977	675,387	691,324
Net Income Before Cumulative Effect of Change in Accounting Principle	624,855	437,276	87,173	398,616	396,931
Cumulative Effect of Change in Accounting Principle, Net of Income Tax (1)	-	(7,131)	-	-	-
Net Income	624,855	430,145	87,173	398,616	396,931
Preferred Stock Dividends	10,892	11,032	11,032	10,994	11,028
Net Income Available to Common	$ 613,963	$ 419,113	$ 76,141	$ 387,622	$ 385,903
Net Income Per Share Available to Common					
Basic					
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.25	$ 3.72	$ 0.66	$ 3.35	$ 3.30
Cumulative Effect of Change in Accounting Principle, Net of Income Tax (1)	-	(0.06)	-	-	-
Net Income Per Share Available to Common	$ 5.25	$ 3.66	$ 0.66	$ 3.35	$ 3.30
Diluted					
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.15	$ 3.66	$ 0.65	$ 3.30	$ 3.24
Cumulative Effect of Change in Accounting Principle, Net of Income Tax (1)	-	(0.06)	-	-	-
Net Income Per Share Available to Common	$ 5.15	$ 3.60	$ 0.65	$ 3.30	$ 3.24
Average Number of Common Shares					
Basic	116,876	114,597	115,335	115,765	116,934
Diluted	119,188	116,519	117,245	117,488	119,102

(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.

At December 31	**2004**	**2003**	**2002**	**2001**	**2000**
Balance Sheet Data:					
Net Oil and Gas Properties	$5,101,603	$4,248,917	$3,321,548	$3,055,910	$2,525,007
Total Assets	5,798,923	4,749,015	3,813,568	3,414,044	3,001,253
Long-Term Debt	1,077,622	1,108,872	1,145,132	855,969	859,000
Shareholders' Equity	2,945,424	2,223,381	1,672,395	1,642,686	1,380,925

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 substantial proved reserves in the United States, Canada, offshore Trinidad and, to a lesser extent, the United Kingdom North Sea. EOG operates under a consistent business and operational 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, with a below average debt-to-total capitalization ratio.

EOG had another year of record operating earnings in 2004. Net income available to common for 2004 of $614 million was up 47% over 2003 earnings of $419 million, attributable primarily to higher commodity prices and increased production. At December 31, 2004, EOG's total reserves were 5.6 trillion cubic feet equivalent, an increase of 430 billion cubic feet equivalent (Bcfe), or 8% higher than 2003.

Operations

Several important developments have occurred since January 1, 2004.

United States and Canada. During 2004, EOG opened a new office in Fort Worth, Texas to expand its drilling success in the Barnett Shale play of the Fort Worth Basin. EOG made significant gas discoveries in the non-core portion of the trend located south and west of the city of Fort Worth. EOG plans to focus on increasing production and further defining the play's ultimate size during 2005.

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 smaller wells in large acreage plays, which in the aggregate will 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. In mid-2004, EOG began natural gas sales to the National Gas Company of Trinidad and Tobago (NGC) under a fifteen-year take-or-pay contract. This gas is being resold by NGC to an anhydrous ammonia plant located in Point Lisas, Trinidad. The plant is owned by Nitrogen (2000) Unlimited (N2000). At December 31, 2004, EOG's subsidiary, EOG Resources NITRO2000 Ltd., owned an approximate 23% equity interest in N2000. Under the contract, EOG supplies approximately 60 million cubic feet per day (MMcfd) gross of natural gas to NGC.

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 Trinidadian 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 anticipates that its existing position with the supply contracts to the two ammonia plants and the new methanol plant, will continue to give its portfolio an even broader exposure to United States and Canada natural gas fundamentals.

In 2004, EOG continued its progress in the Southern Gas Basin of the United Kingdom North Sea. A development well was drilled in the Valkyrie field and commenced production in August 2004. In addition, the production facilities were installed in the Arthur field, which was discovered in 2003, and production commenced in January 2005. EOG continues to review additional opportunities in this area and expects to participate in several exploration wells in 2005.

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, 2004, EOG's debt-to-total capitalization ratio was 27%, down from 33% at year-end 2003. By primarily utilizing cash provided from its operating activities and proceeds from stock options exercised in 2004, EOG funded its $1.5 billion exploration and development expenditures, paid down $31 million of debt, redeemed all 500 outstanding shares of Series D Preferred Stock for $50 million and increased the dividend paid to common shareholders by 20%. In addition, in 2005, EOG's Board of Directors increased the quarterly cash dividend on common stock by 33%. As management currently assesses price forecast and demand trends for 2005, EOG believes that operations and capital expenditure activity can essentially be funded by cash from operations.

For 2005, EOG's estimated exploration and development expenditure budget is approximately $1.6 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 continues to believe EOG has 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, 2004 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 2004, net operating revenues increased $527 million to $2,271 million. Total wellhead revenues, which are revenues generated from sales of natural gas, crude oil, condensate and natural gas liquids from producing wells, increased 27% to $2,301 million as compared to $1,818 million in 2003. Natural Gas Revenues consists of natural gas wellhead revenues and revenues from marketing activities associated with the sales and purchases of natural gas. Revenues from natural gas marketing activities were $2 million for each of 2004 and 2003. Crude oil, condensate and natural gas liquids revenues represent solely wellhead revenues for these products. Wellhead volume and price statistics for the years ended December 31, were as follows:

	2004	2003	2002
Natural Gas Volumes (MMcf per day) (1)			
United States	631	638	635
Canada	212	165	154
Trinidad	186	152	135
United Kingdom	7	-	-
Total	1,036	955	924
Average Natural Gas Prices ($/Mcf) (2)			
United States	$ 5.72	$ 5.06	$ 2.89
Canada	5.22	4.66	2.67
Trinidad	1.51	1.35	1.20
United Kingdom	5.14	-	-
Composite	**4.86**	**4.40**	**2.60**
Crude Oil and Condensate Volumes (MBbl per day) (1)			
United States	21.1	18.5	18.8
Canada	2.7	2.3	2.1
Trinidad	3.6	2.4	2.4
Total	27.4	23.2	23.3
Average Crude Oil and Condensate Prices ($/Bbl) (2)			
United States	$ 40.73	$30.24	$24.79
Canada	37.68	28.54	23.62
Trinidad	39.12	28.88	23.58
Composite	**40.22**	**29.92**	**24.56**
Natural Gas Liquids Volumes (MBbl per day) (1)			
United States	4.8	3.2	2.9
Canada	0.8	0.6	0.8
Total	5.6	3.8	3.7
Average Natural Gas Liquids Prices ($/Bbl) (2)			
United States	$ 27.79	$21.53	$14.76
Canada	23.23	19.13	11.17
Composite	**27.13**	**21.13**	**14.05**
Natural Gas Equivalent Volumes (MMcfe per day) (3)			
United States	786	768	765
Canada	233	183	171
Trinidad	207	166	150
United Kingdom	7	-	-
Total	1,233	1,117	1,086
Total Bcfe (3) Deliveries	451.5	407.8	396.3

(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) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil, condensate and natural gas liquids.

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 MMcf per day, or 8%, to 1,036 MMcf per day for 2004 from 955 MMcf per day in 2003, due to a 47 MMcf per day, or 28%, increase in Canada; a 34 MMcf per day, or 22%, increase in Trinidad; and a 7 MMcf per day increase in the United Kingdom due to commencement of production in August 2004, partially offset by a 7 MMcf per day, or 1% decline in the United States. The increased deliveries in Canada (47 MMcf per day) 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 MMcf per day) 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 MMcf per day).

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 MBbl per day, or 18%, to 27.4 MBbl per day from 23.2 MBbl per day for 2003. The increase was mainly due to production from new wells in the United States (2.6 MBbl per day) and higher production in Trinidad from the Parula wells (0.8 MBbl per day) and from the U(a) block as a result of new production (0.4 MBbl per day).

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.

2003 compared to 2002. Wellhead natural gas revenues for 2003 increased $657 million, or 75%, due to increases in the composite average wellhead natural gas price and natural gas deliveries. The composite average wellhead price for natural gas increased 69% to $4.40 per Mcf for 2003 from $2.60 per Mcf in 2002.

Natural gas deliveries increased to 955 MMcf per day for 2003 from 924 MMcf per day for the comparable period in 2002. The overall increase in natural gas deliveries was primarily due to an increase in Canada of 7% to 165 MMcf per day and an increase in Trinidad of 13% to 152 MMcf per day in 2003. The 7%, or 11 MMcf per day, increase in Canada was primarily attributable to a major property acquisition in the fourth quarter. The 13%, or 17 MMcf per day, increase in Trinidad was attributable to a full year of sales to the CNCL ammonia plant versus only six months of sales in 2002.

Natural gas marketing activities increased natural gas revenues by $2 million and $37 million for 2003 and 2002, respectively.

Wellhead crude oil and condensate revenues increased $45 million, or 22%, due to increases in the composite average wellhead crude oil and condensate price. The composite average wellhead crude oil and condensate price for 2003 was $29.92 per barrel compared to $24.56 per barrel for 2002.

Natural gas liquids revenues were $11 million higher than a year ago primarily due to a 50% increase in the composite average price and a 3% increase in deliveries.

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. During 2002, EOG recognized losses on mark-to-market commodity derivative contracts of $49 million, which included realized losses of $21 million and a $2 million collar premium payment.

Operating and Other Expenses

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 rates of lease and well, 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 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).

Depreciation, depletion and amortization (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).

General and administrative (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 Statement of Financial Accounting Standards (SFAS) No. 144 - "Accounting for the Impairment or Disposal of Long-Lived Assets" 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) and an increase in state income taxes ($2 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). As a result of these changes, 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.

2003 compared to 2002. During 2003, operating expenses of $1,047 million were $133 million higher than the $914 million incurred in 2002. The following table presents the costs per Mcfe for the years ended December 31:

	2003	2002
Lease and Well, including Transportation	$0.52	$0.45
DD&A..	1.08	1.00
G&A..	0.25	0.22
Taxes Other than Income	0.21	0.18
Interest Expense, Net	0.14	0.15
Total Per-Unit Costs	**$2.20**	**$2.00**

The higher per-unit rates of lease and well, DD&A, G&A and taxes other than income for 2003 compared to 2002 were due primarily to the reasons set forth below.

Lease and well expenses of $213 million were $33 million higher than 2002 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 ($15 million) and Canada ($4 million); increased lease and well administrative expenses in the United States ($7 million); and changes in the Canadian exchange rate ($6 million).

DD&A expenses of $442 million increased $44 million from the prior year due primarily to more relative production from higher cost properties in the United States ($20 million) and Canada ($5 million); increased production in Canada ($3 million) and Trinidad ($2 million) and changes in the Canadian exchange rate ($8 million). Also, included in DD&A expenses for 2003 was $5 million of accretion expense related to SFAS No. 143 - "Accounting for Asset Retirement Obligations."

G&A expenses of $100 million were $11 million higher than the period a year ago due primarily to expanded operations ($9 million) and increased insurance expense ($5 million), partially offset by decreased legal costs ($3 million).

Taxes other than income of $86 million were $14 million higher than the prior year period primarily due to an increase of approximately $35 million as a result of increased wellhead revenues as previously discussed, partially offset by $24 million of severance tax credits from the qualification of wells for a Texas high cost gas severance tax exemption.

Exploration costs of $76 million were $16 million higher than a year ago due primarily to an increase in technical staff costs across EOG ($7 million) and increased geological and geophysical expenditures in the United States ($5 million) and Trinidad ($3 million).

Impairments increased $21 million to $89 million compared to a year ago due to higher amortization of unproved leases in the United States ($25 million). Total impairments under SFAS No. 144 - "Accounting for the Impairment or Disposal of Long-Lived Assets" for 2003 and 2002 were $25 million and $30 million, respectively.

Other Income (Expense), Net for 2003 included foreign currency transaction gains of $9 million as a result of applying the changes in the Canadian exchange rate to certain intercompany short-term loans that eliminate in consolidation and income from equity investments of $4 million.

Income tax provision increased $184 million to $217 million for 2003 as compared to 2002 primarily resulting from higher income before income taxes for federal ($187 million) and state ($4 million), expiration of the tight gas sands federal income tax credit as of December 31, 2002 ($4 million), and higher effective foreign income tax rates ($4 million), primarily offset by net tax benefit associated with the Canadian tax law change ($14 million).

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2004 included funds generated from operations, funds from new borrowings and proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan. Primary cash outflows included funds used in operations, exploration and development expenditures, oil and gas property acquisitions, repayment of debt, redemption of preferred stock, common stock repurchases and dividends.

2004 compared to 2003. Net operating cash inflows 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 investing cash outflows 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 by 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.

2003 compared to 2002. Net operating cash inflows of $1,249 million in 2003 increased $638 million as compared to 2002 primarily reflecting an increase wellhead commodity revenues of $713 million and favorable changes in working capital and other liabilities of $117 million, partially offset by an increase in cash operating expenses of $75 million, an increase in current tax expense of $75 million and an increase in realized losses from mark-to-market commodity derivative contracts of $24 million.

Net investing cash outflows of $1,207 million in 2003 increased by $391 million as compared to 2002 due primarily to increased additions to oil and gas properties of $485 million, which includes $366 million related to two Canadian asset purchases, partially offset by favorable changes in working capital related to investing activities of $82 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 by financing activities was $57 million in 2003 versus cash provided of $211 million in 2002. Financing activities for 2003 included repayment of the outstanding balances of commercial paper borrowings and the uncommitted line of credit of $22 million and $14 million, respectively, repurchases of EOG's common stock of $21 million, cash dividend payments of $31 million and proceeds of $35 million from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan.

Exploration and Development Expenditures

The table below sets out components of exploration and development expenditures for the years ended December 31, 2004, 2003 and 2002, along with the total budgeted for 2005, excluding acquisitions (in millions):

	Actual			Budgeted 2005
	2004	**2003**	**2002**	**(excluding acquisitions)**
Expenditure Category				
Capital				
Drilling and Facilities	$1,120	$ 731	$ 595	
Leasehold Acquisitions	143	59	39	
Producing Property Acquisitions	52	405	71	
Capitalized Interest	10	9	9	
Subtotal	1,325	1,204	714	
Exploration Costs	94	76	60	
Dry Hole Costs	92	41	47	
Exploration and Development Expenditures	1,511	1,321	821	Approximately $1,600
Asset Retirement Costs (1)	16	12	-	
Deferred Income Tax on Acquired Properties	(17)	-	15	
Total (2)	**$1,510**	**$1,333**	**$ 836**	

(1) The Asset Retirement Costs are netted with $1 million net gains recognized upon settlement of asset retirement obligations for each of 2004 and 2003. 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.

(2) Pro forma total expenditures for 2002 are not presented since the pro forma application of SFAS No. 143 to the prior periods would not result in pro forma total expenditures materially different from the actual amounts reported.

Exploration and development expenditures of $1.5 billion for 2004 were $190 million higher than the prior year due primarily to increased drilling expenditures ($439 million) resulting from higher exploration and development activities in Canada and Trinidad and higher cost structures in the United States and Canada; increased lease acquisitions in the United States ($84 million), primarily in the non-core Barnett Shale area and, to a lesser extent, in South Texas; and changes in the Canadian exchange rate ($20 million); partially offset by decreased property acquisitions ($353 million). The higher cost structure was primarily due to increases in materials and services across the industry. The 2004 exploration and development expenditures of $1.5 billion 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 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. (See Note 11 to the Consolidated Financial Statements.)

Presented below is a summary of EOG's 2005 natural gas financial collar contracts at February 25, 2005, 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 swap contracts that cover periods beyond March 2005. Moreover, EOG has not entered into any additional natural gas financial collar contracts or natural gas or crude oil financial price swap contracts since December 31, 2004. EOG accounts for these collar and swap contracts using mark-to-market accounting.

Natural Gas Financial Collar Contracts

		Floor Price		Ceiling Price		
2005	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average ($/MMBtu)	Settlement Price ($/MMBtu)
Jan(1)	75,000	$ 7.65 - 8.00	$ 7.77	$ 8.90 - 9.50	$ 9.10	$ 6.35
Feb(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32	6.36
Mar(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32	6.24

(1) Notional volumes of 25,000 MMBtud of the January 2005 collar contracts were purchased at a premium of $0.10 per MMBtu.
(2) The collar contracts for February 2005 and March 2005 were purchased at a premium of $0.10 per MMBtu.

Financing

EOG's long-term debt-to-total capitalization ratio was 27% as of December 31, 2004 compared to 33% as of December 31, 2003.

During 2004, total long-term debt decreased $31 million to $1,078 million (see Note 2 to the Consolidated Financial Statements). The estimated fair value of EOG's long-term debt at December 31, 2004 and 2003 was $1,146 million and $1,175 million, respectively, based upon quoted market prices and, where such prices were not available, upon interest rates currently available to EOG at yearend. EOG's debt is primarily at fixed interest rates. At December 31, 2004, a 1% decline in interest rates would result in a $59 million increase in the estimated fair value of the fixed rate obligations (see Note 11 to the Consolidated Financial Statements).

During 2004, EOG utilized commercial paper, and during 2003, EOG utilized commercial paper and committed bank loans, in addition to operating cash flows, to fund its operations. These loans are more fully described in Note 2 to the Consolidated Financial Statements. While EOG maintains a $600 million commercial paper program, the maximum outstanding at any time during 2004 was $321 million, and the amount outstanding at yearend was $92 million. EOG considers this excess availability, which is contractually backed by the $600 million Revolving Credit Agreement with domestic and foreign lenders described in Note 2, combined with the $688 million of availability under its shelf registration described below, to be ample to meet its ongoing operating needs.

Based on resources available at December 31, 2004, during 2005, EOG plans to replace the Senior Unsecured Term Loan Facility due 2005 with long-term debt. In 2004, the short-term commercial paper loan balance was reduced ($6 million) and the $100 million, 6.50% Notes were paid off by long-term debt refinancing.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2004 (in thousands):

Contractual Obligations[1]	**Total**	**2005**	**2006 - 2008**	**2009 - 2010**	**2011 & beyond**
Long-Term Debt [2]	$1,077,622	$ 166,800	$ 400,822	$ -	$ 510,000
Non-cancelable Operating Leases	45,784	13,497	20,934	5,594	5,759
Drilling Rig Commitments	2,214	1,142	1,072	-	-
Pipeline Transportation Service Commitments [3]	128,983	21,697	49,518	19,139	38,629
Seismic Purchase Obligations	7,904	7,904	-	-	-
Other Purchase Obligations	2,918	1,628	1,290	-	-
Total Contractual Obligations	**$1,265,425**	**$ 212,668**	**$ 473,636**	**$ 24,733**	**$ 554,388**

(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 the Consolidated Financial Statements. In addition, this table does not include EOG's pension or postretirement benefit obligations. See Note 6 to the Consolidated Financial Statements.

(2) Commercial paper and the Senior Unsecured Term Loan Facility due 2005 are classified as long-term debt on the Consolidated Balance Sheets based on EOG's intent and ability to ultimately replace such amounts with other long-term debt. See Note 2 to the Consolidated Financial Statements.

(3) Amounts shown are based on current pipeline transportation rates and the Canadian foreign currency exchange rate at December 31, 2004. 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 25, 2005, 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 $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 2004, 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 2004 was the Canadian Dollar. While the continued strengthening of the Canadian Dollar in 2004 impacted both the revenues and expenses recorded on the income statements of EOG's Canadian subsidiaries, its impacts on the items were not to the same extent. 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 the 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, 2004, EOG recorded the fair value of the swap of $23.1 million in Other Liabilities in the Liabilities section of the Consolidated Balance Sheets. Changes in the fair value of the foreign currency swap resulted in no net impact to the Consolidated Statements of Income. The after-tax net impact from the foreign currency swap transaction resulted in a negative change of $3.8 million for the year ended December 31, 2004. 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 2005, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2005 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 $21 million for net income and operating cash flow. EOG is not impacted as significantly by changing crude oil price. EOG's price sensitivity for each $1.00 per barrel change in average wellhead crude oil prices is approximately $6.5 million for net income and operating cash flow. For information regarding EOG's natural gas hedge position as of December 31, 2004, see Note 11 to the 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 credit worthiness 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 2005 exploration and development expenditures, excluding acquisitions, are approximately $1.6 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 2005 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 2005 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.

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.

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 due to the requirement of a significant capital investment. Such exploratory drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify development when the investment is made and additional exploratory wells are either in progress or firmly planned. All other exploratory wells that do not meet these criteria are expensed after one year. As of December 31, 2004 and 2003 EOG had exploratory drilling costs of $4.3 million and $4.5 million, respectively, related to an outside operated, deepwater offshore Gulf of Mexico discovery that has been deferred for more than one year and will require significant future capital expenditures before production can commence. These costs meet the accounting requirements outlined above for continued capitalization. As of December 31, 2004 and 2003, there were no material exploratory drilling costs capitalized for more than one year for projects that did not require a major capital investment. 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.

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. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. 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. 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 accounts 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 is recognized for such options. As allowed by SFAS No. 123 - "Accounting for Stock-Based Compensation" issued in 1995, EOG has 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 2002, the Financial Accounting Standards Board (FASB) issued SFAS No. 148 – "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123." In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment," which supersedes SFAS No. 148. 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) will be effective for interim or annual reporting periods beginning on or after June 15, 2005. EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 using the modified prospective method. EOG expects that the adoption of SFAS No. 123(R) would reduce second half 2005 net earnings by a pre-tax amount of approximately $10 million which includes approximately $0.5 million 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 $29 million, $12 million and $5 million for 2004, 2003 and 2002, 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 and tubular steel; the availability of pipeline transportation capacity; the extent to which EOG can replicate on its other Barnett Shale acreage the results of its most recent Barnett Shale wells; the results of wells yet to be drilled that are necessary to test whether substantial Barnett Shale acreage positions outside of Johnson and Parker Counties, Texas, contain suitable drilling prospects; 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; and financial market conditions. In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements might not occur. EOG undertakes no obligations 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 interest rate risk and commodity price risk is discussed respectively in the Financing and Outlook sections of the "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***

Not Applicable.

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 recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms.

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, 2004. 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, 2004, 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 auditors have 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, 2004 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, 2004, 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, 2004, 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, 2004, under the caption "Compensation of Directors and Executive Officers" of Item 1.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management*

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, 2004, under the captions "Election of Directors" and "Compensation of Directors and Executive Officers" of Item 1.

Equity Compensation Plan Information

The Company has various plans under which employees and nonemployee members of the Board of Directors of the Company 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 the Company'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, 2004.

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	3,561,527	$46.02	3,622,857 (1) (2)
Equity Compensation Plans Not Approved by Security Holders	3,722,168	$33.03 (3)	85,970 (4) (5)
Total	**7,283,695**	**$39.42 (3)**	**3,708,827**

(1) Of these securities, 256,590 shares remain available for purchase under the Employee Stock Purchase Plan.
(2) Of these securities, 1,071,324 could be issued as restricted stock or restricted stock units under the 1992 Stock Plan.
(3) Weighted-average exercise price does not include 43,875 phantom stock units in the 1996 Deferral Plan which are included in column (a).
(4) Of these securities, 11,043 phantom stock units remain available for issuance under the 1996 Deferral Plan.
(5) Of these securities, 85,970 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 the Company 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, restricted stock units are converted into one share of EOG common stock and released to the employee.

Individual Equity Compensation Arrangement Not Approved by Security Holders. The Board of Directors of the Company approved a one-time grant of 35,000 stock options to nonemployee directors of the Company in 1998, including a grant to Frank Wisner, of which 2,500 shares remain outstanding. The grant has a 10-year term and vested 50% on the first anniversary and 50% on the second anniversary of the date of grant.

Deferral Plan Phantom Stock Account. The Board of Directors of the Company approved the 1996 Deferral Plan, under which payment of base salary, annual bonus and directors fees may be deferred into a phantom stock account. Participants may also defer receipt of shares of EOG common stock from the exercise of a stock option or release of restricted stock or restricted stock units into the 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 60,000 shares have been registered for issuance under the plan. As of December 31, 2004, 48,957 phantom stock units had been issued and 11,043 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, 2004, under the caption "Ratification of Appointment of Auditors - General" of Item 2.

PART IV

ITEM 15. *Financial Statements and Financial Statement Schedule and Exhibits*

(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-5 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 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. 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 public accountants 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, 2004. 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, 2004, EOG's internal control over financial reporting is effective based on those criteria.

Deloitte & Touche LLP, independent public accountants, 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 24, 2005

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, 2004 and 2003, 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, 2004. 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, 2004, 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 schedules, 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 schedules, 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, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, 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, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2005

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

Year Ended December 31	2004	2003	2002
Net Operating Revenues			
Natural Gas	$ 1,843,895	$ 1,537,352	$ 915,129
Crude Oil, Condensate and Natural Gas Liquids	458,446	283,042	227,309
Losses on Mark-to-Market Commodity Derivative Contracts	(33,449)	(80,414)	(48,508)
Other, Net	2,333	4,695	752
Total	2,271,225	1,744,675	1,094,682
Operating Expenses			
Lease and Well, including Transportation	271,086	212,601	179,429
Exploration Costs	93,941	76,358	60,228
Dry Hole Costs	92,142	41,156	46,749
Impairments	81,530	89,133	68,430
Depreciation, Depletion and Amortization	504,403	441,843	398,036
General and Administrative	115,013	100,403	88,952
Taxes Other Than Income	133,915	85,867	71,881
Total	1,292,030	1,047,361	913,705
Operating Income	979,195	697,314	180,977
Other Income (Expense), Net	9,945	15,273	(1,651)
Income Before Interest Expense and Income Taxes	989,140	712,587	179,326
Interest Expense			
Incurred	72,759	67,252	68,641
Capitalized	(9,631)	(8,541)	(8,987)
Net Interest Expense	63,128	58,711	59,654
Income Before Income Taxes	926,012	653,876	119,672
Income Tax Provision	301,157	216,600	32,499
Net Income Before Cumulative Effect of Change in Accounting Principle	624,855	437,276	87,173
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	(7,131)	-
Net Income	624,855	430,145	87,173
Preferred Stock Dividends	10,892	11,032	11,032
Net Income Available to Common	**$ 613,963**	**$ 419,113**	**$ 76,141**
Net Income Per Share Available to Common			
Basic			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.25	$ 3.72	$ 0.66
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	(0.06)	-
Net Income Available to Common	$ 5.25	$ 3.66	$ 0.66
Diluted			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.15	$ 3.66	$ 0.65
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	(0.06)	-
Net Income Available to Common	$ 5.15	$ 3.60	$ 0.65
Average Number of Common Shares			
Basic	116,876	114,597	115,335
Diluted	119,188	116,519	117,245
Comprehensive Income			
Net Income	$ 624,855	$ 430,145	$ 87,173
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustment	77,925	123,811	4,315
Foreign Currency Swap Transaction, Net of Income Tax Benefit of $1,972	(3,844)	-	-
Available-for-Sale Security Transactions	-	-	926
Comprehensive Income	**$ 698,936**	**$ 553,956**	**$ 92,414**

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	2004	2003
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 20,980	$ 4,443
Accounts Receivable, Net	447,742	295,118
Inventories	40,037	21,922
Assets from Price Risk Management Activities	10,747	-
Income Taxes Receivable	3,232	7,976
Deferred Income Taxes	22,227	31,548
Other	41,838	35,007
Total	586,803	396,014
Oil and Gas Properties (Successful Efforts Method)	9,599,276	8,189,062
Less: Accumulated Depreciation, Depletion and Amortization	(4,497,673)	(3,940,145)
Net Oil and Gas Properties	5,101,603	4,248,917
Other Assets	110,517	104,084
Total Assets	**$ 5,798,923**	**$ 4,749,015**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 424,581	$ 282,379
Accrued Taxes Payable	51,116	33,276
Dividends Payable	7,394	6,175
Liabilities from Price Risk Management Activities	-	37,779
Deferred Income Taxes	103,933	73,611
Other	45,180	43,299
Total	632,204	476,519
Long-Term Debt	1,077,622	1,108,872
Other Liabilities	241,319	171,115
Deferred Income Taxes	902,354	769,128
Shareholders' Equity		
Preferred Stock, $.01 Par, 10,000,000 Shares Authorized:		
Series B, 100,000 Shares Issued, Cumulative, $100,000,000 Liquidation Preference	98,826	98,589
Series D, 500 Shares Issued, Cumulative, $50,000,000 Liquidation Preference	-	49,827
Common Stock, $.01 Par, 320,000,000 Shares Authorized and 124,730,000 Shares Issued	201,247	201,247
Additional Paid in Capital	21,047	1,625
Unearned Compensation	(29,861)	(23,473)
Accumulated Other Comprehensive Income	148,015	73,934
Retained Earnings	2,706,845	2,121,214
Common Stock Held in Treasury, 5,802,556 shares at December 31, 2004 and 8,819,600 shares at December 31, 2003	(200,695)	(299,582)
Total Shareholders' Equity	2,945,424	2,223,381
Total Liabilities and Shareholders' Equity	**$ 5,798,923**	**$ 4,749,015**

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 Amounts)

	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, 2001	$ 147,582	$ 201,247	$ -	$ (14,953)	$ (55,118)	$ 1,668,708	$ (304,780)	$ 1,642,686
Net Income	-	-	-	-	-	87,173	-	87,173
Amortization of Preferred Stock Discount	417	-	-	-	-	(417)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,615)	-	(10,615)
Common Stock Dividends Declared, $.16 Per Share	-	-	-	-	-	(18,499)	-	(18,499)
Translation Adjustment	-	-	-	-	4,315	-	-	4,315
Available-for-Sale Security Transactions	-	-	-	-	926	-	-	926
Treasury Stock Purchased	-	-	-	-	-	-	(63,139)	(63,139)
Treasury Stock Issued Under:								
Stock Option Plans	-	-	(9,457)	-	-	(2,402)	28,666	16,807
Employee Stock Purchase Plan	-	-	(39)	-	-	-	2,301	2,262
Tax Benefits from Stock Options Exercised	-	-	5,167	-	-	-	-	5,167
Restricted Stock and Units	-	-	4,329	(4,951)	-	-	622	-
Amortization of Unearned Compensation	-	-	-	4,871	-	-	-	4,871
Treasury Shares Issued as Compensation	-	-	-	-	-	-	441	441
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, $0.19 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, $0.24 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

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	2004	2003	2002
Cash Flows From Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	$ 624,855	$ 430,145	$ 87,173
Items Not Requiring Cash			
Depreciation, Depletion and Amortization	504,403	441,843	398,036
Impairments	81,530	89,133	68,430
Deferred Income Taxes	204,231	191,726	82,179
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	7,131	-
Other, Net	4,580	1,033	17,333
Dry Hole Costs	92,142	41,156	46,749
Mark-to-Market Commodity Derivative Contracts			
Total Losses	33,449	80,414	48,508
Realized Losses	(82,644)	(44,870)	(21,136)
Collar Premium	(520)	(3,003)	(1,825)
Tax Benefits from Stock Options Exercised	29,396	11,926	5,168
Other, Net	537	2,141	(1,978)
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	(151,799)	(27,945)	(59,957)
Inventories	(17,898)	(2,840)	(57)
Accounts Payable	136,716	74,645	(21,468)
Accrued Taxes Payable	18,197	12,056	(85,208)
Other Liabilities	(1,764)	(3,257)	7,816
Other, Net	(2,683)	(15,314)	(1,199)
Changes in Components of Working Capital Associated with Investing and Financing Activities	(28,381)	(36,944)	43,093
Net Cash Provided by Operating Activities	1,444,347	1,249,176	611,657
Investing Cash Flows			
Additions to Oil and Gas Properties	(1,416,684)	(1,245,539)	(760,876)
Proceeds from Sales of Assets	13,459	13,553	7,514
Changes in Components of Working Capital Associated with Investing Activities	26,788	38,491	(43,557)
Other, Net	(20,471)	(13,946)	(19,213)
Net Cash Used in Investing Activities	(1,396,908)	(1,207,441)	(816,132)
Financing Cash Flows			
Net Commercial Paper and Line of Credit Borrowings (Repayments)	(6,250)	(36,260)	39,163
Long-Term Debt Borrowings	150,000	-	250,000
Long-Term Debt Repayments	(175,000)	-	-
Dividends Paid	(37,595)	(31,294)	(29,152)
Redemption of Preferred Stock	(50,000)	-	-
Treasury Stock Purchased	-	(21,295)	(63,038)
Proceeds from Stock Options Exercised	75,510	35,138	17,339
Other, Net	97	(3,485)	(3,008)
Net Cash Provided by (Used in) Financing Activities	(43,238)	(57,196)	211,304
Effect of Exchange Rate Changes on Cash	12,336	10,056	507
Increase (Decrease) in Cash and Cash Equivalents	16,537	(5,405)	7,336
Cash and Cash Equivalents at Beginning of Year	4,443	9,848	2,512
Cash and Cash Equivalents at End of Year	**$ 20,980**	**$ 4,443**	**$ 9,848**

The accompanying notes are an integral part of these 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 revenue and expenses during the reporting period. Actual results could differ from those estimates.

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

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, marketable securities, commodity derivative contracts, accounts receivable, accounts payable 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 2 for fair value of long-term debt).

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 due to the requirement of a significant capital investment. Such exploratory drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify development when the investment is made and additional exploratory wells are either in progress or firmly planned. All other exploratory wells that do not meet these criteria are expensed after one year. As of December 31, 2004 and 2003, EOG had exploratory drilling costs of $4.3 million and $4.5 million, respectively, related to an outside operated, deepwater offshore Gulf of Mexico discovery that has been deferred for more than one year and will require significant future capital expenditures before production can commence. These costs meet the accounting requirements outlined above for continued capitalization. As of December 31, 2004 and 2003, there were no material exploratory drilling costs capitalized for more than one year for projects that did not require a major capital investment. 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. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. 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. 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, 2004, EOG elected not to designate any of its 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 bases (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 revenue and expenses are translated at average exchange rates prevailing during the year. Translation adjustments are included in Accumulated Other Comprehensive Income (Loss). 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 for additional information to reconcile the difference between the Average Number of Common Shares outstanding for basic and diluted net income per share).

Stock Options. EOG accounts 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 is recognized for such options. As allowed by SFAS No. 123 - "Accounting for Stock-Based Compensation" issued in 1995, EOG has 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 of common stock for 2004, 2003 and 2002, had compensation costs been recorded in accordance with SFAS No. 123, are presented below (in millions, except per share data):

	2004	2003	2002
Net Income Available to Common - As Reported	$ 614.0	$ 419.1	$ 76.1
Deduct: Total stock-based employee compensation expense, Net of Income Tax	(11.9)	(13.9)	(13.7)
Net Income Available to Common - Pro Forma	$ 602.1	$ 405.2	$ 62.4
Net Income per Share Available to Common			
Basic - As Reported	$ 5.25	$ 3.66	$ 0.66
Basic - Pro Forma	$ 5.15	$ 3.54	$ 0.54
Diluted - As Reported	$ 5.15	$ 3.60	$ 0.65
Diluted - Pro Forma	$ 5.05	$ 3.48	$ 0.53

For grants made prior to August 2004, the fair value of each option grant is estimated using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants in 2004, 2003 and 2002, respectively: (1) dividend yield of 0.4%, 0.4% and 0.4%, (2) expected volatility of 35%, 43% and 45%, (3) risk-free interest rate of 2.5%, 3.4% and 3.7% and (4) expected life of 2.8 years, 5.2 years and 5.3 years.

Beginning in August 2004, EOG's stock options 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). The fair value of each Capped Option grant is estimated using a Monte Carlo Simulation Model assuming a dividend yield of 0.4%, expected volatility of 31%, risk-free interest rate of 4.24% and a weighted-average expected life of 4.83 years. During 2004, approximately 1,377,000 stock options were granted at a weighted average fair value of $21.06 and were included in the above pro forma employee stock based compensation expense calculation. Approximately 200,000 of the stock options were granted before August 2004 with an average fair value of $16.04, based on the Black-Scholes Option-Pricing Model. Approximately 1,177,000 of the stock options were granted with the Capped Option feature since August 1, 2004, with an average fair value of $21.91, based on the Monte Carlo Simulation Model. The average fair values for the stock options granted during 2003 and 2002 were $16.55 and $14.79, 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.

New Accounting Pronouncements. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 - "Accounting for Asset Retirement Obligations" effective for fiscal years beginning after June 15, 2002. SFAS No. 143 essentially requires entities to record the fair value of a liability for legal obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. EOG adopted the statement on January 1, 2003. The impact of adopting the statement results in an after-tax charge of $7.1 million, which was reported in the first quarter of 2003 as cumulative effect of change in accounting principle.

During the third quarter of 2003, the SEC made comments to other registrants that oil and gas mineral rights acquired should be classified as an intangible asset pursuant to SFAS No. 141 – "Business Combinations," and SFAS No. 142 – "Goodwill and Other Intangible Assets." On September 2, 2004, FASB Staff Position 142-2, "Application of FASB Statement No. 142, "Goodwill and Other Intangible Assets," to Oil- and Gas-Producing Entities" was issued. The FASB staff believes that the scope exception in paragraph 8(b) of Statement 142 extends to its disclosure provisions for drilling and mineral rights of oil- and gas-producing entities. Accordingly, the SEC comments made to the other registrants have no impact on EOG's financial statements.

On April 1, 2004, EOG adopted prospectively FASB Staff Position 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 for further information on EOG's postretirement plan).

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 viewed to be inconsistent with international trade protocols by the European Union. EOG expects the net effect of the phase out of the ETI and the phase in of this new deduction to result in favorable adjustments to the effective tax rate for 2005 and subsequent years. Under the guidance in FASB Staff Position 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 FASB 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.

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. The deduction is subject to a number of limitations and, currently, uncertainty remains as to how to interpret some provisions in the Act. The Act limits the qualified dividends to the greater of $500 million or the amount of earnings permanently reinvested outside the United States, as reported in the 2002 financial statements, which was $550 million. In addition, a comprehensive analysis of foreign legal and tax ramifications must be completed before such dividends are declared. As such, EOG is not yet in a position to decide on whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the United States. EOG expects to be in a position to complete the assessment by September 30, 2005.

In December 2002, the FASB issued SFAS No. 148 – "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123." In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment," which supersedes SFAS No. 148. 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) will be effective for interim or annual reporting periods beginning on or after June 15, 2005. EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 using the modified prospective method. EOG expects that the adoption of SFAS No. 123(R) would reduce second half 2005 net earnings by a pre-tax amount of approximately $10 million, taking into consideration the estimated forfeitures and cancellations. The amount includes approximately $0.5 million 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 $29 million, $12 million and $5 million for 2004, 2003 and 2002, respectively (see Note 6 for further information on EOG's stock-based compensation plans).

2. Long-Term Debt

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

	2004	**2003**
Commercial Paper	$ 91,800	$ 98,050
Senior Unsecured Term Loan Facility due 2005	75,000	150,000
6.50% Notes due 2004	-	100,000
6.70% Notes due 2006	126,870	126,870
6.50% Notes due 2007	100,000	100,000
6.00% Notes due 2008	173,952	173,952
6.65% Notes due 2028	140,000	140,000
7.00% Subsidiary Debt due 2011	220,000	220,000
4.75% Subsidiary Debt due 2014	150,000	-
Total	**$ 1,077,622**	**$ 1,108,872**

During 2004, EOG utilized commercial paper and during 2003, EOG utilized commercial paper and short-term funding from uncommitted credit facilities, both bearing market interest rates, for various corporate financing purposes. Commercial paper and uncommitted credit borrowings are classified as long-term debt based on EOG's intent and ability to ultimately replace such amounts with other long-term debt.

On July 23, 2003, EOG entered into a new three-year Revolving Credit Agreement (Agreement) with domestic and foreign lenders which provides for $600 million in long-term committed credit, and concurrently cancelled the existing $300 million 364-day credit facility and $300 million five-year credit facility scheduled to expire in July 2003 and July 2004, respectively. This Agreement provides EOG the ability to replace the commercial paper, uncommitted credit borrowing and any maturity of debt. Advances under the Agreement bear interest based upon a base rate or a Eurodollar rate at the option of EOG. The Agreement also provides for the allocation, at the option of EOG, of up to $75 million of the $600 million to its Canadian subsidiary. Advances to the Canadian subsidiary, should they occur, would be guaranteed by EOG and would bear interest at the option of the Canadian subsidiary based upon a Canadian prime rate or a Canadian banker's acceptance rate. EOG also has the option to issue up to $100 million in letters of credit as part of this Agreement. No amounts were borrowed under this Agreement at December 31, 2004. The applicable base rates for this Facility, had there been any amounts borrowed under this Agreement would have been 5.25% and 4.00% at December 31, 2004 and December 31, 2003, respectively. The applicable Eurodollar rates for this Facility, had there been any amounts borrowed under this Agreement would have been 2.90% and 1.62% at December 31, 2004 and December 31, 2003, respectively.

EOG maintains a three-year Senior Unsecured Term Loan Facility (Facility) with a group of banks whereby the banks lent EOG $150 million with a maturity date of October 30, 2005. This Facility calls for interest to be charged at a spread over LIBOR (London InterBank Offering Rate) or the base rate at EOG's option, and contains 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 remaining $75 million balance is classified as long-term debt based on EOG's intent and ability to ultimately replace such amounts with other long-term debt. The applicable interest rates for the Facility were 3.17% and 1.88% at December 31, 2004 and December 31, 2003, respectively.

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 US$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 CAD$201.3 million with a 5.275% interest rate.

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. The weighted average interest rate for the commercial paper was 1.45% for 2004.

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

At December 31, 2004, the aggregate annual maturities of long-term debt were $75 million for 2005, $127 million in 2006, $100 million for 2007, $174 million for 2008 and zero for 2009.

Both EOG's Credit Agreement and Facility contain certain restrictive covenants, including a maximum debt-to-total capitalization ratio of 65% and a minimum ratio of EBITDAX (earnings before interest, taxes, DD&A, and exploration expense) to interest expense of at least three times. Other than these covenants, EOG does not have any other financial covenants in its financing agreements. EOG continues to comply with these two covenants and does not view them as materially restrictive.

Shelf Registration. As of February 25, 2005, the amount available under various filed registration statements with the SEC for the offer and sale from time to time of EOG debt securities, preferred stock and/or common stock totaled $688 million.

Fair Value Of Long-Term Debt. At December 31, 2004 and 2003, EOG had $1,078 million and $1,109 million, respectively, of long-term debt, which had fair values of approximately $1,146 million and $1,175 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 yearend.

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, 2004, 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 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.

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, 2001	124,730	(9,278)	115,452
Treasury Stock Purchased	-	(1,703)	(1,703)
Treasury Stock Issued Under Stock Option Plans	-	870	870
Treasury Stock Issued Under Employee Stock Purchase Plan	-	69	69
Restricted Stock and Units	-	19	19
Treasury Stock Issued as Compensation	-	13	13
Balance at December 31, 2002	124,730	(10,010)	114,720
Treasury Stock Purchased	-	(626)	(626)
Treasury Stock Issued under Stock Option Plans	-	1,485	1,485
Treasury Stock Issued Under Employee Stock Purchase Plan	-	74	74
Restricted Stock and Units	-	247	247
Treasury Stock Issued as Compensation	-	10	10
Balance at December 31, 2003	124,730	(8,820)	115,910
Treasury Stock Purchased	-	(160)	(160)
Treasury Stock Issued Under Stock Option Plans	-	2,961	2,961
Treasury Stock Issued Under Employee Stock Purchase Plan	-	68	68
Restricted Stock and Units	-	148	148
Balance at December 31, 2004	124,730	(5,803)	118,927

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 will effect 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 stock split will have 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 (Preferred Share) for $90, once the Rights become exercisable. This portion of a Preferred 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 Preferred 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 the 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).

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 $0.01 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 $0.01 per Right. The redemption price will be adjusted if EOG has a 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 Series E Junior Participating Preferred Stock with the rights and preferences described above. On February 24, 2005, EOG's Board of Directors increased the authorized shares of Series E Junior Participating Preferred Stock to 3,000,000 as a result of the two-for-one stock split mentioned above. Currently, there are no shares of the Series E Junior Participating Preferred Stock 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.

On July 25, 2000, EOG's Board of Directors authorized 500 shares of Flexible Money Market Cumulative Preferred Stock, Series D, with a liquidation preference of $100,000 per share (the "Series D"). Dividends were payable on the shares only if declared by EOG's Board of Directors and were cumulative. The initial dividend rate on the shares was 6.84% until December 15, 2004. Through December 15, 2004, dividends were payable, if declared, on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. On December 15, 2004, EOG redeemed all 500 outstanding shares of the Series D at a redemption price of $100,000 per share plus accumulated and unpaid dividends for a total of $50 million. On February 24, 2005, EOG filed a Certificate of Elimination with the Secretary of State of the State of Delaware to eliminate the Series D from EOG's Restated Certificate of Incorporation, as amended.

4. Other Income (Expense), Net

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. Other Income (Expense), Net for 2003 included foreign currency transaction gains of $9 million and income from equity investments of $4 million. The foreign currency transaction gain and loss amounts for 2004 and 2003 are results of applying the changes in the Canadian exchange rate to certain intercompany short-term loans that eliminate in consolidation.

5. Income Taxes

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

	2004	2003
Current Deferred Income Tax Assets		
Commodity Hedging Contracts	$ (7,701)	$ 9,739
Deferred Compensation Plans	6,488	4,994
Net Operating Loss Carryforward	-	5,225
United Kingdom Net Operating Loss Carryforward (Current Portion)	10,160	-
Other	13,280	11,590
Total Current Deferred Income Tax Assets	22,227	31,548
Current Deferred Income Tax Liabilities		
Timing Differences Associated With Different Yearends in Foreign Jurisdictions	103,903	73,611
Other	30	-
Total Current Deferred Income Tax Liabilities	103,933	73,611
Total Net Current Deferred Income Tax Liabilities	**$ 81,706**	**$ 42,063**
Noncurrent Deferred Income Tax Assets (included in Other Assets)		
United Kingdom Net Operating Loss Carryforward	$ 21,764	$ 3,688
United Kingdom Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	(20,465)	-
Total Noncurrent Deferred Income Tax Assets	**$ 1,299**	**$ 3,688**
Noncurrent Deferred Income Tax Assets		
Non-Producing Leasehold Costs	$ 41,718	$ 36,154
Seismic Costs Capitalized for Tax	25,563	21,365
Alternative Minimum Tax Credit Carryforward	-	3,869
Other	22,740	20,124
Total Noncurrent Deferred Income Tax Assets	90,021	81,512
Noncurrent Deferred Income Tax Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	974,492	837,189
Capitalized Interest	16,683	13,451
Other	1,200	-
Total Noncurrent Deferred Income Tax Liabilities	992,375	850,640
Total Net Noncurrent Deferred Income Tax Liability	**$ 902,354**	**$ 769,128**
Total Net Deferred Income Tax Liability	**$ 982,761**	**$ 807,503**

The components of income before income taxes were as follows (in thousands):

	2004	2003	2002
United States	$ 641,973	$ 442,109	$ 37,354
Foreign	284,039	211,767	82,318
Total	**$ 926,012**	**$ 653,876**	**$ 119,672**

The principal components of EOG's income tax provision for the years indicated below were as follows (in thousands):

	2004	2003	2002
Current:			
Federal	$ 58,148	$ 3,844	$ (61,013)
State	3,137	880	(5,130)
Foreign	35,641	20,150	16,463
Total	96,926	24,874	(49,680)
Deferred:			
Federal	156,862	151,389	57,232
State	7,985	4,052	(358)
Foreign	39,384	36,285	25,305
Total	204,231	191,726	82,179
Income Tax Provision	**$ 301,157**	**$ 216,600**	**$ 32,499**

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

	2004	2003	2002
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	0.74	0.73	0.22
Income Tax Provision Related to Foreign Operations	(1.83)	(0.05)	(3.54)
Change in Canadian Federal Tax Rate	-	(2.16)	-
Change in Canadian Provincial Tax Rate	(0.58)	-	-
Tight Gas Sands Federal Income Tax Credits	-	-	(3.57)
Other	(0.81)	(0.40)	(0.95)
Effective Income Tax Rate	**32.52%**	**33.12%**	**27.16%**

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. The deduction is subject to a number of limitations and, currently, uncertainty remains as to how to interpret some provisions in the Act. The Act limits the qualified dividends to the greater of $500 million or the amount of earnings permanently reinvested outside the United States, as reported in the 2002 financial statements, which was $550 million. In addition, a comprehensive analysis of foreign legal and tax ramifications must be completed before such dividends are declared. As such, EOG is not yet in a position to decide on whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the United States. EOG expects to be in a position to complete the assessment by September 30, 2005.

EOG's foreign subsidiaries' undistributed earnings of approximately $1 billion at December 31, 2004 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 in the form of dividends, 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.

A foreign net operating loss of $80 million, of which $55 million was incurred during 2004, will be carried forward indefinitely until utilized.

EOG had an alternative minimum tax (AMT) 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 2004, 2003 and 2002, EOG's total contributions to these pension plans amounted to $10.6 million, $8.2 million and $8.0 million, respectively.

In addition, EOG's Canadian subsidiary maintains a non-contributory defined contribution pension plan and a matched defined contribution savings plan and EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. These pension plans are available to most employees of the Canadian and Trinidadian subsidiaries and EOG's combined contributions to these pension plans were approximately $860,000, $630,000 and $460,000 for 2004, 2003 and 2002, respectively.

EOG's United Kingdom subsidiary introduced a pension plan as of January 2005. The United Kingdom subsidiary will include a defined non-contributory pension plan and a matched defined contribution savings plan. The pension plan will be available to all employees of the United Kingdom subsidiary.

Postretirement Plan

EOG has postretirement medical and dental benefits in place for eligible employees and their eligible dependents. Benefits are provided under the provisions of a contributory defined dollar benefit plan. EOG accrues these postretirement benefit costs over the service lives of the employees expected to be eligible to receive such benefits. The following table summarizes EOG's postretirement benefit plan as of December 31 of the years indicated as follows (in thousands):

	2004	2003	2002
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	$ 3,011	$ 1,875	$ 2,021
Service Cost	175	175	139
Interest Cost	136	131	115
Plan Participants' Contributions	73	64	58
Amendments	-	773	-
Benefits Paid	(136)	(102)	(95)
Actuarial (Gain) Loss	(1,276)	95	(363)
Benefit Obligation at Yearend	**$ 1,983**	**$ 3,011**	**$ 1,875**
Change in Plan Asset			
Fair Value of Plan Asset at Beginning of Year	$ -	$ -	$ -
Employer Contributions	63	38	37
Plan Participants' Contributions	73	64	58
Benefits Paid	(136)	(102)	(95)
Fair Value of Plan Asset at Yearend	**$ -**	**$ -**	**$ -**
Reconciliation of Funded Status to Balance Sheet			
Funded Status	$ 1,983	$ 3,011	$ 1,875
Unrecognized Net Actuarial Gain (Loss)	1,158	(64)	35
Unrecognized Prior Service Cost	(1,517)	(1,647)	(948)
Accrued Benefit Cost at Yearend	**$ 1,624**	**$ 1,300**	**$ 962**
Components of Net Periodic Benefit Cost			
Service Cost	$ 175	$ 175	$ 139
Interest Cost	136	131	115
Amortization of Prior Service Cost	129	75	75
Recognized Net Actuarial Gain	(53)	-	(1)
Net Periodic Benefit Cost	**$ 387**	**$ 381**	**$ 328**

Weighted-average discount rate assumptions used in the determination of benefit obligations at December 31, 2004, 2003 and 2002 were 5.95%, 6.15% and 6.40%, respectively. Weighted-average discount rate assumptions used in the determination of net periodic benefit cost for years ended December 31, 2004, 2003 and 2002 were 6.15%, 6.40% and 7.00%, respectively.

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):

	Postretirement Employer-Paid Benefits
2005	$ 84
2006	91
2007	96
2008	103
2009	126
2010 - 2014	924

Postretirement health care trend rates have zero effect on the amounts reported for the postretirement health care plan for both 2004 and 2003. A one-percentage point increase or decrease in EOG's healthcare cost trend rates would have zero impact on the postretirement benefit obligation, as any increase or decrease 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, 2004, 3,708,827 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.

Beginning in August 2004, EOG's stock options 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.

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

	2004		2003		2002	
	Options	Average Grant Price	Options	Average Grant Price	Options	Average Grant Price
Outstanding at January 1	7,751	$ 30.38	7,842	$ 27.31	7,013	$ 24.69
Granted	1,307	63.94	1,515	39.13	1,809	33.82
Exercised	(2,961)	26.85	(1,485)	22.73	(868)	19.90
Forfeited	(140)	38.57	(121)	34.74	(112)	27.64
Outstanding at December 31	5,957	39.32	7,751	30.38	7,842	27.31
Options Exercisable at December 31	3,050	30.37	4,933	27.03	5,041	23.96
Available for Future Grant	3,709		1,178		2,932	

EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 (see Note 1) and as a result, EOG expects the expensing of the stock options would reduce second half 2005 net earnings by a pre-tax amount of approximately $9.5 million.

The following table summarizes certain information for the options outstanding at December 31, 2004 (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**
$ 14.00 to $17.99	362	4	$ 14.53	362	$ 14.53
18.00 to 22.99	512	4	20.05	512	20.05
23.00 to 28.99	44	3	24.97	42	24.85
29.00 to 33.99	1,627	7	33.32	1,067	33.14
34.00 to 39.99	1,905	8	37.47	882	36.75
40.00 to 54.99	292	8	45.60	177	44.03
55.00 to 73.99	1,215	10	64.78	8	61.22
	5,957	**7**	**39.32**	**3,050**	**30.37**

During 2004, 2003 and 2002, EOG repurchased approximately 160,000, 626,000 and 1,703,000 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 $29.4 million, $11.9 million and $5.2 million, for the years 2004, 2003 and 2002, 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, restricted units are 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		
	2004	**2003**	**2002**
Outstanding at January 1	1,026	775	632
Granted	330	372	158
Released	(41)	(103)	(10)
Forfeited or Expired	(32)	(18)	(5)
Outstanding at December 31	1,283	1,026	775
Average Fair Value of Shares Granted During Year	$ 51.43	$ 40.43	$ 32.56

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 2004, 2003 and 2002 was $9.6 million, $6.0 million and $4.9 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, 2004, approximately 256,600 common shares remained available for issuance under the plan. EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 (see Note 1) and as a result, EOG expects the expense associated with the ESPP would reduce second half 2005 net earnings by a pre-tax amount of approximately $0.5 million.

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

	2004	**2003**	**2002**
Approximate Number of Participants	450	410	350
Shares Purchased	68	74	69
Aggregate Purchase Price	$3,021	$2,599	$2,261

7. Commitments and Contingencies

Letters Of Credit. At December 31, 2004 and 2003, EOG had standby letters of credit and guarantees outstanding totaling approximately $433 million and $266 million, respectively. Of these amounts, $370 million and $220 million, respectively, represent guarantees of subsidiary indebtedness included under Note 2 "Long-Term Debt" while $63 million and $46 million, respectively, primarily represent guarantees of payment obligations on behalf of subsidiaries. As of February 25, 2005, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2004, 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 transportation rates and the foreign currency exchange rates at December 31, 2004, are as follows (in thousands):

	Total Minimum Commitments
2005	$ 45,868
2006 - 2008	72,814
2009 - 2010	24,733
2011 and beyond	44,388
	$ 187,803

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2015. Rental expenses associated with these leases amounted to $26 million, $22 million and $21 million for 2004, 2003 and 2002, 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 amounts):

	2004	2003	2002
Numerator for basic and diluted earnings per share -			
Net income available to common	$ 613,963	$ 419,113	$ 76,141
Denominator for basic earnings per share -			
Weighted average shares	116,876	114,597	115,335
Potential dilutive common shares -			
Stock options	1,780	1,584	1,633
Restricted stock and units	532	338	277
Denominator for diluted earnings per share -			
Adjusted weighted average shares	119,188	116,519	117,245
Net Income Per Share Available to Common			
Basic	$ 5.25	$ 3.66	$ 0.66
Diluted	$ 5.15	$ 3.60	$ 0.65

9. Supplemental Cash Flow Information

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

	2004	2003	2002
Interest	$ 60,967	$ 62,472	$ 54,432
Income taxes	56,654	26,330	15,946

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 and requires selected information about operating segments in interim financial reports. 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 significant international location. 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
2004						
Net Operating Revenues	$ 1,656,325[1]	$ 448,562[1]	$ 153,377	$12,961	$ -	$ 2,271,225[1]
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	936,463	294,571	59,205	34,303	-	1,324,542
Total Assets	3,727,231	1,600,486	401,434	69,772	-	5,798,923
2003						
Net Operating Revenues	$ 1,335,145[2]	$ 309,418[2]	$ 100,112	$ -	$ -	$ 1,744,675[2]
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	605,667	552,164	31,942	14,610	-	1,204,383
Total Assets	3,119,474	1,302,753	309,727	17,061	-	4,749,015
2002						
Net Operating Revenues	$ 846,007[3]	$ 169,106[3]	$ 79,551	$ -	$ 18	$ 1,094,682[3]
Depreciation, Depletion and Amortization	334,318	49,622	14,085	-	11	398,036
Operating Income (Loss)	93,600	40,587	49,450	(250)	(2,410)	180,977
Interest Income	765	229	348	-	-	1,342
Other Income (Expense)	(3,652)	261	394	-	4	(2,993)
Interest Expense, Net	45,907	13,534	211	-	2	59,654
Income (Loss) Before Income Taxes	44,806	27,543	49,981	(250)	(2,408)	119,672
Income Tax Provision (Benefit)	(7,684)	20,359	20,974	300	(1,450)	32,499
Additions to Oil and Gas Properties	517,598	160,840	35,689	-	-	714,127
Total Assets	2,864,862	665,202	283,395	66	43	3,813,568

(1) 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.

(2) 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.

(3) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2002 that totaled $163 million of the consolidated Net Operating Revenues.

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 derivative financial instruments, primarily price swaps and collars, as the means to manage this price risk. In addition to these 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 – "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149, these various 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 these various physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

During 2004, 2003 and 2002, EOG elected not to designate any of its derivative financial contracts as accounting hedges and accordingly, accounted for these derivative financial contracts using mark-to-market accounting. 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. During 2002, EOG recognized losses on mark-to-market commodity derivative contracts of $49 million, which included realized losses of $21 million and a $2 million collar premium payment.

Presented below is a summary of EOG's 2005 natural gas financial collar contracts at December 31, 2004 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 swap contracts that cover periods beyond March 2005. Moreover, EOG has not entered into any additional natural gas financial collar contracts or natural gas or crude oil financial price swap contracts since December 31, 2004. EOG accounts for these collar contracts using mark-to-market accounting. The total fair value of the natural gas financial collar contracts at December 31, 2004 was $11 million.

Natural Gas Financial Collar Contracts

		Floor Price		Ceiling Price	
2005	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average ($/MMBtu)
Jan[1]	75,000	$ 7.65 - 8.00	$ 7.77	$ 8.90 - 9.50	$ 9.10
Feb[2]	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32
Mar[2]	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32

(1) Notional volumes of 25,000 MMBtud of the January 2005 collar contracts were purchased at a premium of $0.10 per MMBtu.
(2) The collar contracts for February 2005 and March 2005 were purchased at a premium of $0.10 per MMBtu.

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):

	2004		2003	
	Carrying Amount	**Estimated Fair Value[1]**	**Carrying Amount**	**Estimated Fair Value[1]**
Long-Term Debt[2]	$ 1,078	$ 1,146	$ 1,109	$ 1,175
NYMEX-Related Commodity Market Positions	11	11	(38)	(38)

(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, 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. The amounts due from an integrated oil and gas company and a utility company at December 31, 2003, which approximated 14% and 11%, respectively, of the United States and Canada net accounts receivable balance, were collected during early 2004. No other individual purchaser accounted for 10% or more of the United States and Canada net accounts receivable balance at December 31, 2004 and 2003. At December 31, 2004, EOG had an allowance for doubtful accounts of $21 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, 2004 and 2003 result 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, 2004, 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 2004, 2003 and 2002, 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 for certain producing fields. As a result, during 2004, 2003 and 2002, EOG recorded in Impairments pre-tax charges of $17 million, $21 million and $30 million, respectively, in the United States operating segment and $8 million, $4 million and $0, respectively, in the Canada operating segment. 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 acquisition costs of unproved properties, including amortization of capitalized interest, were $57 million, $64 million and $38 million for 2004, 2003 and 2002, 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 $7.1 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 2004 (in thousands):

	Asset Retirement Obligations		
	Short-Term	**Long-Term**	**Total**
Balance at December 31, 2003	$ 5,320	$ 118,624	$ 123,944
Liabilities Incurred	2,060	14,728	16,788
Liabilities Settled	(4,831)	(5,422)	(10,253)
Accretion	164	5,423	5,587
Revision	1,333	744	2,077
Reclassification	2,894	(2,894)	-
Foreign Currency Translation	30	586	616
Balance at December 31, 2004	**$ 6,970**	**$ 131,789**	**$ 138,759**

Pro forma net income and earnings per share are not presented for the comparable period in 2002 because the pro forma application of SFAS No. 143 to the prior period would not result in pro forma net income and earnings per share materially different from the actual amounts reported for the period in the accompanying Consolidated Statements of Income.

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

EOG, through certain wholly owned subsidiaries, owns equity interests in two Trinidadian companies: Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000). During the first quarters of 2003 and 2004, EOG completed separate share sale agreements whereby a portion of the EOG subsidiaries' shareholdings in CNCL and N2000 was sold to a third party energy company. The sales left EOG with equity interests of 12% in CNCL and 23% in N2000 and did not result in any gain or loss.

In February 2005, a portion of EOG's shareholdings in N2000 was sold to a subsidiary of one of the other shareholders. The sale resulted in a pre-tax gain of approximately $2 million. EOG's equity interest in N2000 is now 10%.

The other shareholders in CNCL are Ferrostaal AG, Clico Energy Company Limited, KBRDC CNC (Cayman) Ltd. and Koch CNC (Nevis) LLC. At December 31, 2004, investment in CNCL was $15 million. CNCL commenced production in June 2002, and at December 31, 2004, was producing approximately 1,850 metric tons of ammonia daily. At December 31, 2004, CNCL had a long-term debt balance of $203 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 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 2004, EOG recognized equity income of $5 million and received cash dividends of $5 million from CNCL.

The other shareholders in N2000 are FS Petrochemicals (St. Kitts) Limited, CE Limited, KBRDC Nitrogen 2000 (St. Lucia) Ltd. and Koch N2000 (Nevis) LLC. At December 31, 2004, investment in N2000 was $26 million. N2000 commenced production in August 2004, and at December 31, 2004, was producing approximately 1,950 metric tons of ammonia daily. At December 31, 2004, N2000 had a long-term debt balance of $228 million, which is non-recourse to N2000's shareholders. At December 31, 2004, 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 $7 million of which is net to EOG's interest. The Shareholders' Agreement 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 2004, EOG recognized equity income of $6 million.

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 US$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 US$140.5 million on October 1, 2003. The remainder of the purchase price, US$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 US$5 million. In late December 2003, a Canadian subsidiary of EOG closed another property acquisition for US$46 million.

Oil and Gas Producing Activities

The following disclosures are made in accordance with 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, 2004, 2003 and 2002 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, 2004, 2003 and 2002 covered producing areas containing 77%, 72% and 73%, 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, 2004 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

The following table sets forth EOG's net proved and proved developed reserves at December 31 for each of the four years in the period ended December 31, 2004, and the changes in the net proved reserves for each of the three years in the period then ended 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, 2001	2,007.3	644.1	1,145.1	-	3,796.5
Revisions of previous estimates	9.4	4.7	(21.7)	-	(7.6)
Purchases in place	9.9	102.9	-	-	112.8
Extensions, discoveries and other additions	217.0	83.9	232.4	-	533.3
Sales in place	(0.8)	(1.5)	-	-	(2.3)
Production	(236.6)	(56.2)	(49.3)	-	(342.1)
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**

	United States	Canada	Trinidad	United Kingdom	TOTAL
Liquids (MBbl)[2]					
Net proved reserves at December 31, 2001	52,383	6,652	13,099	-	72,134
Revisions of previous estimates	3,543	396	(572)	-	3,367
Purchases in place	624	865	-	-	1,489
Extensions, discoveries and other additions	14,763	279	3,041	-	18,083
Sales in place	(33)	-	-	-	(33)
Production	(7,925)	(1,026)	(874)	-	(9,825)
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**
Bcf Equivalent (Bcfe)[1]					
Net proved reserves at December 31, 2001	2,321.6	684.0	1,223.7	-	4,229.3
Revisions of previous estimates	30.7	7.1	(25.1)	-	12.7
Purchases in place	13.6	108.1	-	-	121.7
Extensions, discoveries and other additions	305.6	85.6	250.6	-	641.8
Sales in place	(1.0)	(1.5)	-	-	(2.5)
Production	(284.2)	(62.4)	(54.5)	-	(401.1)
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**

	United States	Canada	Trinidad	United Kingdom	TOTAL
NET PROVED DEVELOPED RESERVES					
Natural Gas (Bcf) (1)					
December 31, 2001	1,588.4	587.6	620.6	-	2,796.6
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
Liquids (MBbl) (2)					
December 31, 2001	41,205	6,532	8,435	-	56,172
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
Bcf Equivalents (Bcfe) (1)					
December 31, 2001	1,835.7	626.8	671.1	-	3,133.6
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

(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:

	2004	2003
Proved properties.....................................	$ 9,307,422	$ 7,990,675
Unproved properties................................	291,854	198,387
Total	9,599,276	8,189,062
Accumulated depreciation, depletion and amortization	(4,497,673)	(3,940,145)
Net capitalized costs.......................	**$ 5,101,603**	**$ 4,248,917**

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
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	660,799	270,435	46,864	30,910	-	1,009,008
Subtotal	1,050,006	316,283	82,165	58,728	3,443	1,510,625
Asset Retirement Costs (1)	5,644	6,610	1,754	2,223	-	16,231
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	480,257	145,539	23,140	2,812	-	651,748
Subtotal	687,598	562,036	43,829	23,770	4,664	1,321,897
Asset Retirement Costs (1)	8,167	3,552	-	-	-	11,719
Total	$ 695,765	$ 565,588	$ 43,829	$ 23,770	$4,664	$1,333,616
2002						
Acquisition Costs of Properties						
Unproved	$ 28,232	$ 4,754	$ 5,629	$ -	$ -	$ 38,615
Proved	22,589	48,487	-	-	-	71,076
Subtotal	50,821	53,241	5,629	-	-	109,691
Exploration Costs	120,058	25,866	18,117	-	2,384	166,425
Development Costs	423,436	107,952	13,600	-	-	544,988
Subtotal	594,315	187,059	37,346	-	2,384	821,104
Deferred Income Tax on Acquired Properties	-	14,938	-	-	-	14,938
Total (2)	$ 594,315	$ 201,997	$ 37,346	$ -	$2,384	$ 836,042

(1) The Asset Retirement Costs for the United States are netted with $1 million net gains recognized upon settlement of asset retirement obligations for each of 2004 and 2003. 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.

(2) Pro forma total costs incurred for 2002 are not presented as the pro forma application of SFAS No. 143 to the prior period would not result in pro forma total expenditures materially different from the actual amount reported.

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
2004						
Natural Gas, Crude Oil and Condensate 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 Expenses	71,823	10,264	7,109	4,745	-	93,941
Dry Hole Expenses	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 and Condensate 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 Expenses	65,885	5,726	3,997	739	11	76,358
Dry Hole Expenses	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
2002						
Natural Gas, Crude Oil and Condensate Revenues	$ 891,991	$ 170,875	$ 79,551	$ -	$ 21	$ 1,142,438
Other, Net	2,521	(1,769)	-	-	-	752
Total	894,512	169,106	79,551	-	21	1,143,190
Exploration Expenses	52,830	5,529	1,656	152	61	60,228
Dry Hole Expenses	26,107	20,642	-	-	-	46,749
Production Costs	186,041	48,261	9,977	64	7	244,350
Impairments	65,813	2,619	-	-	(2)	68,430
Depreciation, Depletion and Amortization	334,318	49,622	14,085	-	11	398,036
Income (Loss) Before Income Taxes	229,403	42,433	53,833	(216)	(56)	325,397
Income Tax Provision (Benefit)	82,136	10,319	23,971	(70)	(20)	116,336
Results of Operations	$ 147,267	$ 32,114	$ 29,862	$ (146)	$ (36)	$ 209,061

(1) Excludes gains or losses on mark-to-market commodity derivative contracts, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2004.

(2) Other includes other international operations.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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
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
2002					
Future cash inflows	$ 9,826,571	$ 2,989,000	$ 2,303,930	$ -	$15,119,501
Future production costs	(2,212,357)	(586,166)	(433,029)	-	(3,231,552)
Future development costs	(359,787)	(43,876)	(177,275)	-	(580,938)
Future net cash flows before income taxes	7,254,427	2,358,958	1,693,626	-	11,307,011
Future income taxes	(2,214,072)	(653,425)	(558,788)	-	(3,426,285)
Future net cash flows	5,040,355	1,705,533	1,134,838	-	7,880,726
Discount to present value at 10% annual rate	(2,265,700)	(766,567)	(629,024)	-	(3,661,291)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,774,655	$ 938,966	$ 505,814	$ -	$ 4,219,435

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2004:

	United States	Canada	Trinidad	United Kingdom	TOTAL
December 31, 2001	$ 1,710,026	$ 470,477	$ 346,886	$ -	$ 2,527,389
Sales and transfers of oil and gas produced, net of production costs	(705,938)	(122,614)	(69,574)	-	(898,126)
Net changes in prices and production costs	1,561,946	460,977	223,614	-	2,246,537
Extensions, discoveries, additions and improved recovery net of related costs	499,257	123,700	110,415	-	733,372
Development costs incurred	84,300	18,100	13,600	-	116,000
Revisions of estimated development cost	35,255	(11,418)	(20,574)	-	3,263
Revisions of previous quantity estimates	51,227	11,470	(15,634)	-	47,063
Accretion of discount	200,701	59,594	48,622	-	308,917
Net change in income taxes	(692,670)	(135,888)	(87,229)	-	(915,787)
Purchases of reserves in place	28,851	117,958	-	-	146,809
Sales of reserves in place	(715)	(2,827)	-	-	(3,542)
Changes in timing and other	2,415	(50,563)	(44,312)	-	(92,460)
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

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

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

Quarter Ended	Mar 31	Jun 30	Sep 30	Dec 31
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				
Basic [(1)]	$ 0.85	$ 1.22	$ 1.44	$ 1.73
Diluted [(1)]	$ 0.83	$ 1.20	$ 1.42	$ 1.69
Average Number of Common Shares				
Basic	115,645	116,388	117,411	118,070
Diluted	117,621	118,709	119,677	120,556
2003				
Net Operating Revenues	$ 464,669	$ 424,754	$ 458,724	$ 396,528
Operating Income	$ 226,129	$ 176,868	$ 193,312	$ 101,005
Income Before Income Taxes	$ 210,963	$ 165,741	$ 179,604	$ 97,568
Income Tax Provision	74,407	56,950	62,185	23,058
Net Income Before Cumulative Effect of Change in Accounting Principle	136,556	108,791	117,419	74,510
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(7,131)	-	-	-
Net Income	129,425	108,791	117,419	74,510
Preferred Stock Dividends	2,758	2,758	2,758	2,758
Net Income Available to Common	$ 126,667	$ 106,033	$ 114,661	$ 71,752
Net Income Per Share				
Basic [(1)]				
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 1.17	$ 0.93	$ 1.00	$ 0.62
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-	-
Net Income Per Share Available to Common	$ 1.11	$ 0.93	$ 1.00	$ 0.62
Diluted [(1)]				
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 1.15	$ 0.91	$ 0.99	$ 0.61
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-	-
Net Income Per Share Available to Common	$ 1.09	$ 0.91	$ 0.99	$ 0.61
Average Number of Common Shares				
Basic	114,441	114,382	114,616	114,893
Diluted	116,224	116,131	116,370	117,209

(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.

Schedule II

EOG RESOURCES, INC.

VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2004, 2003 and 2002
(In Thousands)

Column A	Column B	Column C	Column D	Column E
Description	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Deductions From Reserves(1)	Balance at End of Year
2004				
Allowance deducted from Accounts Receivable	$ 20,748	$ 45	$ 174	$ 20,619
2003				
Allowance deducted from Accounts Receivable	$ 20,287	$ 506	$ 45	$ 20,748
2002				
Allowance deducted from Accounts Receivable	$ 20,114	$ 182	$ 9	$ 20,287

(1) Represents receivables written off.

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.
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.
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).
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).

Exhibit Number		Description
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).
10.2	-	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).
10.3	-	1992 Stock Plan (As Amended and Restated Effective May 4, 2004) (Exhibit B to EOG's Proxy Statement, dated March 29, 2004, with respect to EOG's Annual Meeting of Shareholders).
10.4(a)	-	1996 Deferral Plan, as amended and restated effective May 8, 2001 (Exhibit 4.4 to Form S-8 Registration Statement No. 333-84014, filed March 8, 2002).
10.4(b)	-	First Amendment to 1996 Deferral Plan, as amended and restated effective May 8, 2001, 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 November 1, 1997 (Exhibit 10.64 to EOG's Annual Report on Form 10-K for the year ended December 31, 1997).
10.5(b)	-	First Amendment to Executive Employment Agreement between EOG and Mark G. Papa, effective as of February 1, 1999 (Exhibit 10.64(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998).
10.5(c)	-	Second Amendment to Executive Agreement between EOG and Mark G. Papa, effective as of June 28, 1999 (Exhibit 10.64(c) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.5(d)	-	Third Amendment to Executive Employment Agreement between EOG and Mark G. Papa, entered into on June 20, 2001, and made effective as of June 1, 2001 (Exhibit 10.10(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.5(e)	-	Change of Control Agreement between EOG and Mark G. Papa, effective as of June 20, 2001 (Exhibit 10.10(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.6(a)	-	Executive Employment Agreement between EOG and Edmund P. Segner, III, effective as of September 1, 1998 (Exhibit 10.65(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998).
10.6(b)	-	First Amendment to Executive Employment Agreement between EOG and Edmund P. Segner, III, effective as of February 1, 1999 (Exhibit 10.65(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998).
10.6(c)	-	Second Amendment to Executive Employment Agreement between EOG and Edmund P. Segner, III, effective as of June 28, 1999 (Exhibit 10.65(c) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.6(d)	-	Third Amendment to Executive Employment Agreement between EOG and Edmund P. Segner, III, entered into on June 22, 2001, and made effective as of June 1, 2001 (Exhibit 10.11(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.6(e)	-	Change of Control Agreement between EOG and Edmund P. Segner, III, effective as of June 22, 2001 (Exhibit 10.11(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).

Exhibit Number		Description
10.7(a)	-	Executive Employment Agreement between EOG and Barry Hunsaker, Jr., effective as of September 1, 1998 (Exhibit 10.66(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.7(b)	-	First Amendment to Executive Employment Agreement between EOG and Barry Hunsaker, Jr., effective as of December 21, 1998 (Exhibit 10.66(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.7(c)	-	Second Amendment to Executive Employment Agreement between EOG and Barry Hunsaker, Jr., effective as of February 1, 1999 (Exhibit 10.66(c) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.7(d)	-	Third Amendment to Executive Employment Agreement between EOG and Barry Hunsaker, Jr., entered into on June 29, 2001, and made effective as of June 1, 2001 (Exhibit 10.12(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.7(e)	-	Change of Control Agreement between EOG and Barry Hunsaker, Jr., effective as of June 29, 2001 (Exhibit 10.12(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.8(a)	-	Executive Employment Agreement between EOG and Loren M Leiker, effective as of March 1, 1998 (Exhibit 10.67(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.8(b)	-	First Amendment to Executive Employment Agreement between EOG and Loren M. Leiker, effective as of February 1, 1999 (Exhibit 10.67(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.8(c)	-	Second Amendment to Executive Employment Agreement between EOG and Loren M. Leiker, entered into on July 1, 2001, and made effective as of June 1, 2001 (Exhibit 10.13(c) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.8(d)	-	Change of Control Agreement between EOG and Loren M. Leiker, effective as of July 1, 2001 (Exhibit 10.13(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.9(a)	-	Executive Employment Agreement between EOG and Gary L. Thomas, effective as of September 1, 1998 (Exhibit 10.68(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.9(b)	-	First Amendment to Executive Employment Agreement between EOG and Gary L. Thomas, effective as of February 1, 1999 (Exhibit 10.68(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
10.9(c)	-	Second Amendment to Executive Employment Agreement between EOG and Gary L. Thomas, entered into on July 1, 2001, and made effective as of June 1, 2001 (Exhibit 10.14(c) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.9(d)	-	Change of Control Agreement between EOG and Gary L. Thomas, effective as of July 1, 2001 (Exhibit 10.14(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.10(a)	-	Change of Control Severance Plan (As Amended and Restated Effective May 8, 2001) (Exhibit 10.15 to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.10(b)	-	First Amendment to Change of Control Severance Plan (As Amended and Restated Effective May 8, 2001), effective as of September 10, 2002 (Exhibit 10.15(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2002).
10.11	-	Employee Stock Purchase Plan (Exhibit 4.4 to Form S-8 Registration Statement No. 333-62256, filed June 4, 2001).

Exhibit Number		Description
10.12(a)	-	Amended and Restated Savings Plan (Exhibit 10.17 to EOG's Annual Report on Form 10-K for the year ended December 31, 2002).
10.12(b)	-	First Amendment to Amended and Restated Savings Plan, dated effective as of December 15, 2003.
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).
10.14	-	Form of Grant Agreement to Non-Employee Directors of EOG (Exhibit 10.21 to EOG's Annual Report on Form 10-K for the year ended December 31, 2002).
*10.15	-	Change of Control Agreement between EOG and Timothy K. Driggers, effective as of August 31, 2004.
*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 28, 2005.
*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.
*99.1	-	Certificate of Adjusted Number of Rights pursuant to Section 12 of Rights Agreement dated February 14, 2000, between EOG and EquiServe Trust Company, N.A., as successor Rights Agent to First Chicago Trust Company of New York, as amended.

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, on the 25th day of February, 2005.

EOG RESOURCES, INC.
(Registrant)

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 by the following persons on behalf of registrant and in the capacities with EOG Resources, Inc. indicated and on the 25th day of February, 2005.

Signature	Title
/s/ MARK G. PAPA (Mark G. Papa)	Chairman 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)