eog resources

CONSISTENCY

2003 Annual Report to Shareholders

FINANCIAL AND OPERATING HIGHLIGHTS

(In millions, except per share data, unless otherwise indicated)	2003	2002	2001
Net Operating Revenues	$ 1,745	$ 1,095	$ 1,656
Income Before Interest Expense and Income Taxes	$ 713	$ 179	$ 677
Net Income Available to Common	$ 419	$ 76	$ 388
Exploration and Development Expenditures	$ 1,333	$ 836	$ 1,163
Wellhead Statistics			
Natural Gas Volumes (MMcfd)	955	924	921
Natural Gas Prices ($/Mcf)	$ 4.40	$ 2.60	$ 3.81
Crude Oil and Condensate Volumes (MBbld)	23.2	23.3	25.8
Crude Oil and Condensate Prices ($/Bbl)	$ 29.92	$ 24.56	$ 24.83
Natural Gas Liquids Volumes (MBbld)	3.8	3.7	4.0
Natural Gas Liquids Prices ($/Bbl)	$ 21.13	$ 14.05	$ 16.89
NYSE Price Range ($/Share)			
High	$ 47.52	$ 44.15	$ 55.50
Low	$ 35.70	$ 30.02	$ 25.80
Close	$ 46.17	$ 39.92	$ 39.11
Cash Dividends Per Common Share	$ 0.180	$ 0.160	$ 0.155
Diluted Average Number of Common Shares	116.5	117.2	117.5

THE COMPANY

EOG Resources, Inc. (EOG) is one of the largest independent (non-integrated) oil and gas companies in the United States and has substantial proved reserves in the U.S., Canada, offshore Trinidad and to a lesser extent, the United Kingdom North Sea. EOG is listed on the New York Stock Exchange and is traded under the ticker symbol "EOG."

2003 HIGHLIGHTS

- EOG delivered net income available to common of $419.1 million, or $3.60 per share as compared to $76.1 million, or $0.65 per share for the full year 2002.
- At December 31, 2003, total company net proved reserves were approximately 5.2 trillion cubic feet equivalent, an increase of 614 billion cubic feet equivalent, or 13 percent higher than 2002.
- EOG's total reserve replacement from all sources was 249 percent of production and total company all-in finding costs were $1.28 per thousand cubic feet equivalent (Mcfe). From drilling alone, EOG replaced 183 percent of production at a finding cost of $1.21 per Mcfe.
- In Trinidad, EOG agreed to a 15-year contract to ultimately supply 87 million cubic feet per day (MMcfd) of natural gas to the M5000 methanol plant, based on current price and operating assumptions.
- EOG closed the largest property acquisition in its history with the purchase of primarily natural gas properties in southeast Alberta, Canada for approximately US $320 million. EOG also established a new international venue in the Southern Gas Basin of the United Kingdom North Sea.
- EOG's annual common stock dividend increased by 25 percent to $0.20 per share, effective July 31, 2003. In February 2004, EOG announced its fourth dividend increase in five years, a 20 percent increase to an indicated annual rate of $0.24 per share, payable April 30, 2004.
- At December 31, 2003, EOG's debt-to-total capitalization ratio was 33.3 percent, down from 40.6 percent at year-end 2002.

Information regarding forward-looking statements is on page 19 of this annual report to shareholders.

CONSISTENCY SETS US APART

At EOG Resources, our strategy continues to be simple, straight-forward and disciplined. To us, being predictable is anything but dull. In fact, we consider it our hallmark.

We *consistently* focus on North American natural gas, augmented with a select number of profitable oil plays. Only international niches that play to our strengths are included in our game plan. We *consistently* grow our company through the drillbit, seeking acquisitions that fit this emphasis. We *consistently* focus on the bottom line, building on our reputation as a low-cost producer with a passion for efficiency. We *consistently* operate a decentralized organization, allowing our explorationists, who are among the best and brightest in the business, a maximum amount of flexibility and a minimum level of bureaucracy. We *consistently* deliver favorable returns to our shareholders.

Mark G. Papa
Chairman and Chief Executive Officer

Edmund P. Segner, III
President and Chief of Staff

2003 HIGHLIGHTS

EOG's penchant for managing the company for the long-term, rather than for fast, short-term attention, is on course. Last year, EOG delivered record operating earnings. Net income available to common was $419.1 million, or $3.60 per share as compared to $76.1 million, or $0.65 per share for the full year 2002, reflecting higher commodity prices. We substantially added to our reserve base by replacing 249 percent of production at an attractive $1.28 per Mcfe finding cost. From drilling alone, we replaced 183 percent of production at a $1.21 per Mcfe finding cost.

Just as important, if not more so, 2003 was a year in which several fundamentals were put in place that set us up for meaningful reserve and production growth — primarily through the drillbit — in 2004, 2005 and 2006.

EOG closed the largest property acquisition in its history on October 1, the purchase of natural gas properties in the Wintering Hills, Drumheller East and

Twining areas of southeast Alberta, Canada, from a subsidiary of Husky Energy Inc. for approximately US $320 million. This tactical move increases EOG's Canadian drilling inventory, primarily in the footprint of our very successful shallow natural gas program in southern Alberta. It also complements EOG's existing Canadian assets by providing incremental reserve potential and significantly increasing our coal bed methane acreage position in the Twining Field.

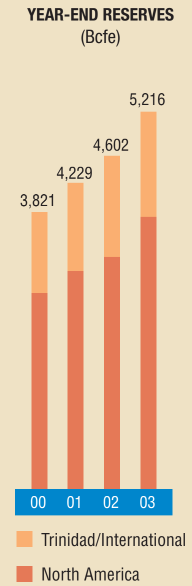
In Trinidad, EOG agreed to a 15-year contract to ultimately supply 87 MMcfd of natural gas to the M5000 methanol plant, based on current price and operating assumptions. Now under construction, this new facility is expected to start up in mid-2005 with EOG supplying 67 MMcfd for the first four years. EOG has no equity investment in this operation. The contract was signed in early 2004.

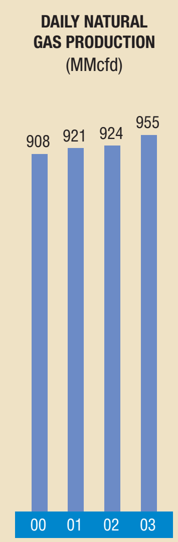
Another highlight of 2003 was the addition of long-term international production growth with a new venue in the Southern Gas Basin of the United Kingdom North Sea. The first production of approximately 40 MMcfd from two farm-in discoveries is expected to begin in late 2004.

Our steady efforts to develop long-term growth through the identification of larger targets has proven a successful supplement to our base program of drilling numerous wells in repeatable technology plays. Based on this stable foundation, last fall EOG announced total company production growth targets of 6.5 percent in 2004, 10 percent in 2005 and 7 percent in 2006.

LOOKING AHEAD

In 2004, we plan to spend a portion of our estimated capital expenditure budget of $1.1 billion (excluding acquisitions) to drill internally generated, 'big target' ideas. North American natural gas continues to be a key component of this effort. When it fits our strategy, we'll make acquisitions that bolster existing drilling programs or offer us incremental exploration and/or production opportunities.





At EOG, energy describes both our industry and the zeal of employees like Big Piney, Wyo. Production Foreman Al Luckow (left) and Senior Gauger Jackie Hunt (right), whose efforts help to maintain the company's reputation as a ***consistent*** *low-cost producer.*

CONSISTENCYCONSISTENCY

CONSISTENCYRELIABILITY

CONSISTENCYCONSISTENCY

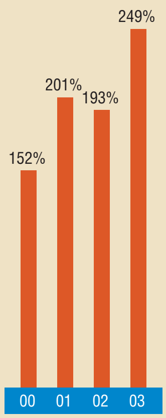
EOG's ***consistent*** *growth through the drillbit strategy offers employees like Oklahoma Production Foreman Rick Burke (left) and Field Drilling Superintendent Stan Rauh (right) tremendous opportunity to extract new reserves to meet America's energy needs.*

C O N S I S T E N C Y C O N S I S T E N C Y

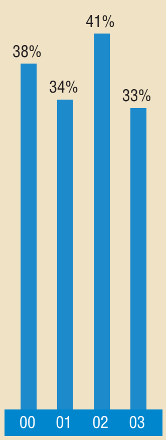
C O N S I S T E N C Y S T A B I L I T Y

C O N S I S T E N C Y C O N S I S T E N C Y

RESERVE REPLACEMENT



YEAR-END DEBT-TO-TOTAL CAPITALIZATION RATIO



Through an aggressive drilling program offshore Trinidad, we are seeking additional reserves with the objective of entering new markets that increasingly are aligning with the North American natural gas business. For example, major liquefied natural gas (LNG) imports are serious contenders to meet increasing U.S. demand. In addition, ammonia, methanol and chemical production is relocating from North America to Trinidad, driven by attractive natural gas feedstock prices in the island nation.

Our successful North Sea base has provided us with a moderate risk entry strategy in building a new international platform. In 2004, we are assessing additional exciting farm-in opportunities.

Looking ahead, EOG's prospects are considerably larger and more visible than in the past. In fact, EOG is prospect rich. However, continued growth through the drillbit demands a dedicated, ongoing, company-wide effort to excel in an environment where the targets are increasingly difficult to identify. Our ability to control costs is critical, as is a very steady pace of activity. We intend to maintain a very active prospect generation program.

Consistently, EOG is on track regarding all these goals.

DOMESTIC NATURAL GAS SUPPLIES REMAIN TIGHT

The domestic natural gas industry in which EOG operates is under considerable stress. According to the National Petroleum Council, natural gas currently fuels approximately 25 percent of U.S. energy, generating about 19 percent of electric power, supplying heat to over 60 million households and providing over 40 percent of all primary energy for industries. However, the gap between domestic natural gas supply and demand is expected to continue to widen, resulting in higher prices and volatility. A recent National Petroleum Council study indicates that, even with increasing LNG imports after 2007, traditional North American supply basins will continue to supply the vast majority of natural gas to serve U.S. markets.

EOG'S PAST IS PROLOGUE FOR FUTURE PERFORMANCE

EOG's stock price increased 16 percent in 2003 and in February 2004, we raised the indicated annual dividend from $0.20 to $0.24 per share, the fourth increase in five years. Over the last four years, we have delivered a 163 percent increase in share price to our shareholders, the best return of any exploration and production company on the Standard & Poor's 500.

EOG continues to have strong debt coverage ratios and our return on equity and return on capital employed are among the best in our peer group. For the second consecutive year, we were ranked by a leading brokerage firm as having the most conservative accounting practices of the large-cap exploration and production companies.

Consistency continues to galvanize the combined efforts of our 1,120 employees as we continue to build a strong exploration and production company that can ride out the peaks and valleys, the ebbs and flows, of the energy business. We've built our workforce with talented technical professionals in their respective fields who thrive in our highly collaborative, decentralized office environment.

In May 2004, Ed Randall, who has been an EOG board member since 1990, will retire. We will miss Ed's astute advice and counsel.

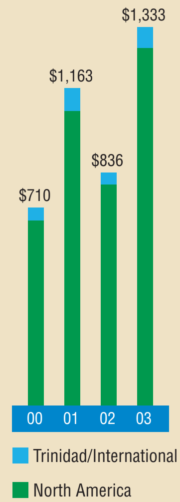
In our estimation, EOG's past performance is the prologue to our future success. We have never felt more confident about this company and our ability to execute our strategy, this year, and in years to come.

Mark G. Papa
Chairman and Chief Executive Officer

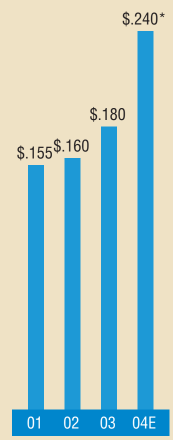
Edmund P. Segner, III
President and Chief of Staff

March 1, 2004

EXPLORATION & DEVELOPMENT EXPENDITURES
(Millions)



CASH DIVIDENDS PER COMMON SHARE



* Indicated current level

*Drilling Superintendent James Szenasy (left) and Senior Production Foreman Randy Lewellen (right) see EOG's growth firsthand in the West Texas Permian Basin where the company's highly successful horizontal drilling program continues to deliver **consistent** results.*

C O N S I S T E N C Y C O N S I S T E N C Y

C O N S I S T E N C Y D E P E N D A B I L I T Y

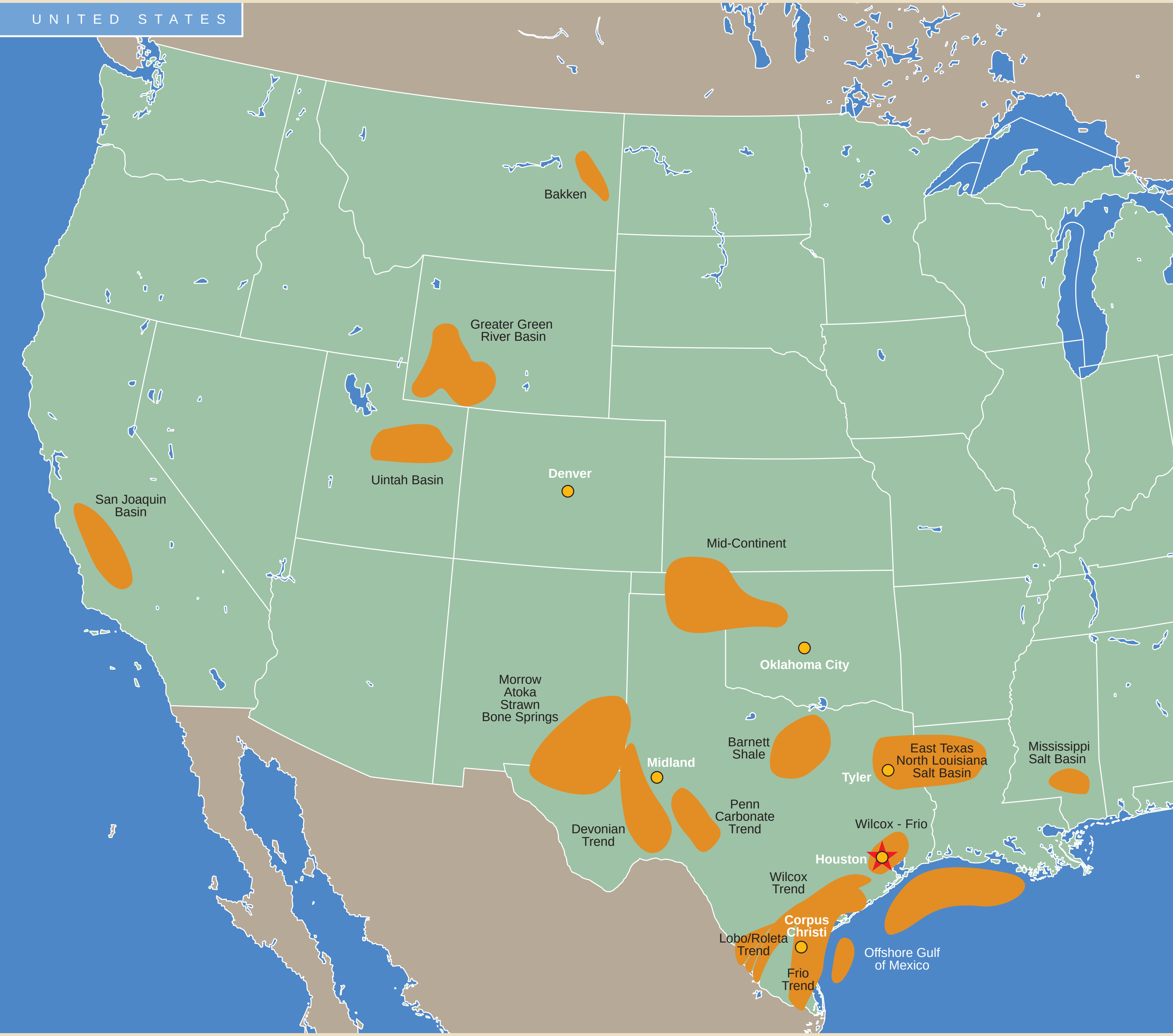
C O N S I S T E N C Y C O N S I S T E N C Y

E O G   O P E R A T I O N S

2003 Production	1,117.2 MMcfed
2003 Reserves	5,216.3 Bcfe

LEGEND

Areas of Operation
Offices
Corporate Headquarters

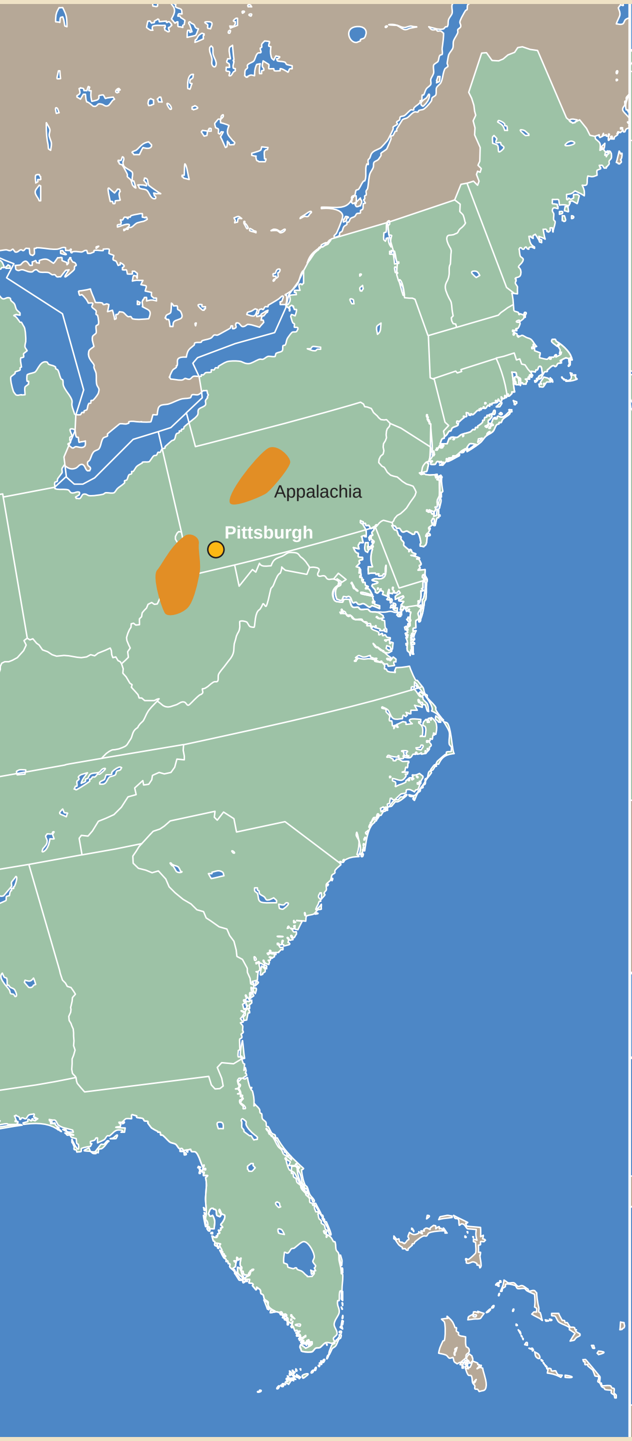


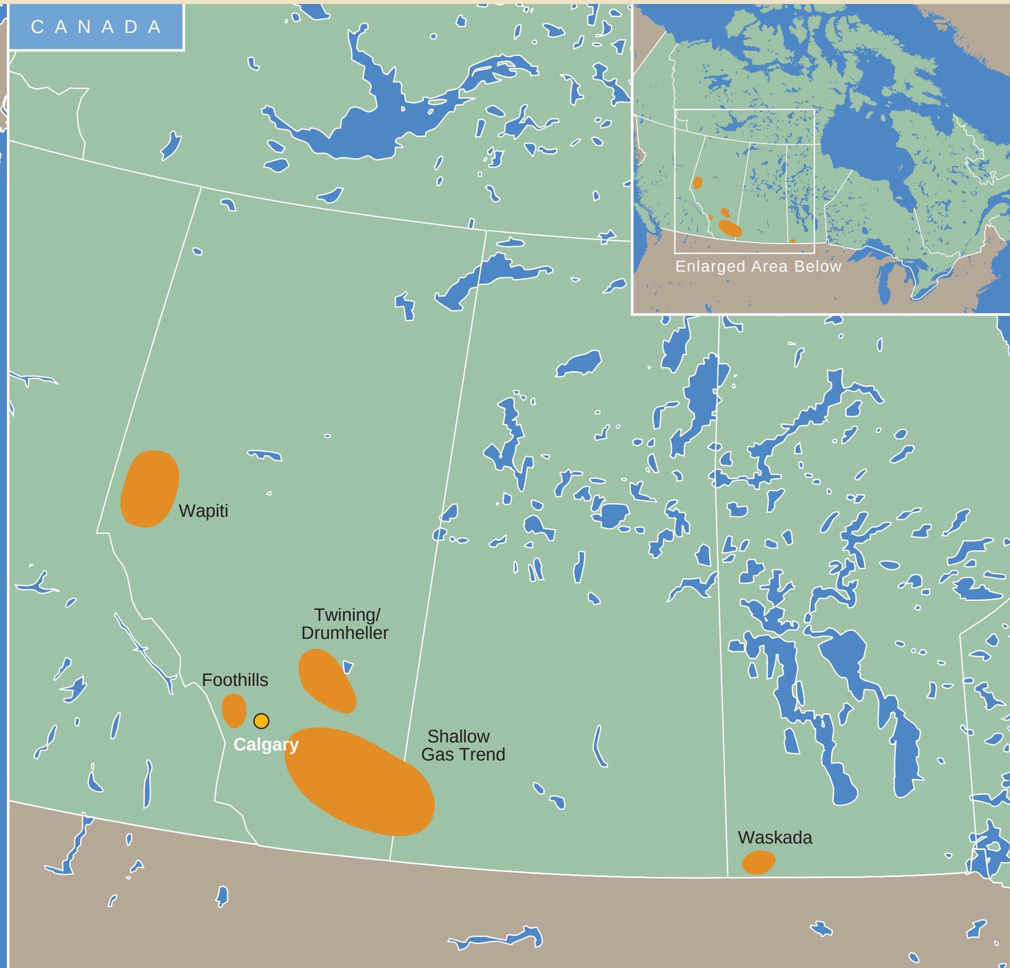
UNITED STATES

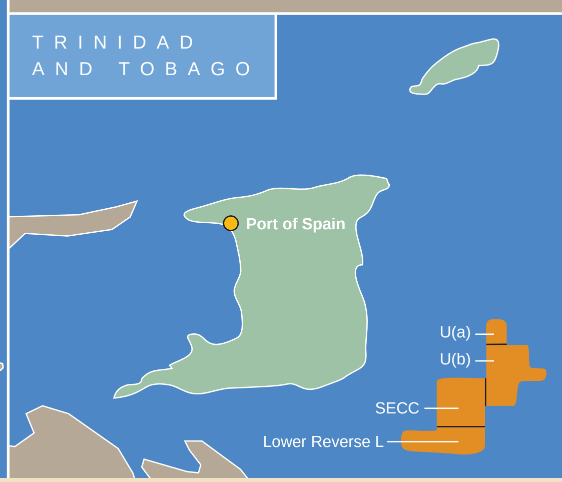
2003 Production	768.2 MMcfed
2003 Reserves	2,539.7 Bcfe

CANADA

2003 Production	182.7 MMcfed
2003 Reserves	1,228.1 Bcfe







TRINIDAD AND TOBAGO

2003 Production	166.3 MMcfed
2003 Reserves	1,388.8 Bcfe

UNITED KINGDOM

2003 Reserves	59.7 Bcfe

FINANCIAL REVIEW

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 gas companies in the United States and has substantial proved reserves in the U.S., Canada, offshore Trinidad and to a lesser extent, the United Kingdom North Sea. EOG operates under a business strategy that focuses predominantly on three factors: achieving a strong reinvestment rate of return on its capital program, drilling internally generated prospects in order to find and develop low cost reserves, and maintaining a strong balance sheet, with a below average debt-to-total capitalization ratio.

EOG had record operating earnings in 2003. Net income available to common for 2003 of $419.1 million, or $3.60 per share, was up 450% over 2002, attributable primarily to higher commodity prices. In addition, EOG substantially added to its reserve base by replacing 249% of production at an all-in finding cost of $1.28 per Mcfe. From drilling alone, EOG replaced 183% of production at a rate of $1.21 per Mcfe.

Operations

Several important developments have occurred since January 1, 2003.

North America. EOG closed the largest property acquisition in its history on October 1, 2003, with the purchase of natural gas properties in the Wintering Hills, Drumheller East and Twining areas of southeast Alberta, Canada, from a subsidiary of Husky Energy Inc. for approximately US $320 million. This transaction increases EOG's drilling inventory in Canada, primarily in the footprint of its very successful shallow natural gas program in southern Alberta. It also complements EOG's existing Canadian assets by providing incremental reserve potential and significantly increasing EOG's coal bed methane acreage position in the Twining Field.

EOG's effort to identify plays with larger reserve potential has proven a successful supplement to its base development and exploitation program in North America. 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 underway in Wyoming, Utah and Texas, including the Barnett Shale, from which more information will become known during 2004.

International. In 2003, Trinidad had its first full year of sales to the CNCL ammonia plant versus only six months of sales in 2002. Also in Trinidad in 2003, construction progressed on the N2000 ammonia plant, which is scheduled to start up in the second half of 2004. EOG will supply 60 MMcfd, gross, and based on current price assumptions, expects to supply 47 MMcfd, net, of natural gas to this facility under a fifteen-year contract. Additionally in Trinidad, EOG signed a fifteen-year contract in early 2004 to supply a portion of the natural gas requirements of the M5000 methanol plant. Currently under construction, start-up of the M5000 facility is planned for mid-2005. When the plant is running at its design capacity, EOG anticipates supplying approximately 95 MMcfd, gross, of natural gas during the first four years and approximately 125 MMcfd, gross, during the remaining eleven years of the contract. Based on current price assumptions, the company expects to supply an average 67 MMcfd, net, during the first four years and 87 MMcfd, net, during the remaining eleven years. The wellhead price will be linked to Caribbean methanol prices but with a floor price. With this new contract, EOG anticipates another significant increase in its Trinidad production next year. In addition, EOG believes that there are additional exploration opportunities in its existing acreage position in Trinidad and continues to pursue additional acreage.

Although EOG continues to focus on North American natural gas, EOG sees an increasing linkage between North American natural gas demand and Trinidadian natural gas supply. For example, LNG imports from existing and planned facilities in Trinidad are serious contenders to meet increasing U.S. demand. In addition, ammonia, methanol and chemical production has been relocating from North America 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, discussed above, will continue to give its portfolio an even broader exposure to North American natural gas fundamentals.

Also in 2003, EOG established a new venue outside of North America with two natural gas discoveries in the Southern Gas Basin of the United Kingdom North Sea. The wells were farm-in opportunities from major oil companies. Production of approximately 40 MMcfd, net, is expected by year-end 2004. EOG is reviewing additional farm-in opportunities in this area and expects to participate in several exploration wells in 2004.

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, 2003, its debt-to-total capitalization ratio was 33.3%, down from 40.6% at year-end 2002. With the net cash provided from operating activities, EOG funded its entire $917 million capital program, paid down $36 million of debt, closed $405 million of acquisitions and, in May 2003, increased the dividend paid to common shareholders by 25%. As management currently assesses price forecast and demand trends for 2004, EOG believes that operations and capital expenditure activity can essentially be funded by cash from operations.

For 2004, EOG's estimated capital expenditure budget is approximately $1.1 billion, excluding acquisitions. EOG plans to spend about 5% of this estimated capital expenditure budget to drill new, internally generated, bigger target ideas. North American natural gas continues to be a key component of this effort. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management believes EOG has one of the strongest prospect inventories in EOG's history.

Finding Costs and Reserve Replacement

During 2003, EOG replaced 249% of its production at an all-in $1.28 per Mcfe finding cost. In North America, EOG had 259% reserve replacement at $1.36 per Mcfe. EOG replaced 189% of production at a $0.63 per Mcfe finding costs in its Trinidad and United Kingdom activities. An external review of approximately 70% of EOG's reserves was conducted by the independent reserve engineering firm of DeGolyer and MacNaughton (D&M). For the sixteenth consecutive year, D&M reported no material differences overall between their independent estimates and EOG's internal estimates.

RESULTS OF OPERATIONS

The following review of operations for each of the three years in the period ended December 31, 2003 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page 22.

Net Operating Revenues

During 2003, net operating revenues increased $650 million to $1,745 million. Total wellhead revenues increased 65% to $1,818 million as compared to 2002. Wellhead volume and price statistics for the specified years were as follows:

	Year Ended December 31,		
	2003	2002	2001
Natural Gas Volumes (MMcf per day)			
United States	638	635	680
Canada	165	154	126
Trinidad	152	135	115
Total	955	924	921
Average Natural Gas Prices ($/Mcf)			
United States	$ 5.06	$ 2.89	$ 4.26
Canada	4.66	2.67	3.78
Trinidad	1.35	1.20	1.22
Composite	4.40	2.60	3.81

	Year Ended December 31,		
	2003	2002	2001
Crude Oil and Condensate Volumes (MBbl per day)			
United States	18.5	18.8	22.0
Canada	2.3	2.1	1.7
Trinidad	2.4	2.4	2.1
Total	23.2	23.3	25.8
Average Crude Oil and Condensate Prices ($/Bbl)			
United States	$ 30.24	$24.79	$25.06
Canada	28.54	23.62	22.70
Trinidad	28.88	23.58	24.14
Composite	29.92	24.56	24.83
Natural Gas Liquids Volumes (MBbl per day)			
United States	3.2	2.9	3.5
Canada	0.6	0.8	0.5
Total	3.8	3.7	4.0
Average Natural Gas Liquids Prices ($/Bbl)			
United States	$ 21.53	$14.76	$17.17
Canada	19.13	11.17	15.05
Composite	21.13	14.05	16.89
Natural Gas Equivalent Volumes (MMcfe per day)			
United States	768	765	833
Canada	183	171	139
Trinidad	166	150	128
Total	1,117	1,086	1,100
Total Bcfe Deliveries	408	396	401

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 a year ago. 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.

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.

2002 compared to 2001. During 2002, net operating revenues decreased $560 million to $1,095 million. Total wellhead revenues of $1,105 million decreased by $435 million, or 28%, as compared to 2001.

Wellhead natural gas revenues for 2002 decreased approximately $405 million primarily due to a general decline in the composite average wellhead natural gas price, partially offset by an increase in natural gas deliveries in Canada and Trinidad. The composite average wellhead price for natural gas decreased 32% to $2.60 per Mcf for 2002 compared to $3.81 per Mcf in 2001.

Natural gas deliveries increased slightly to 924 MMcf per day for 2002 compared to 921 MMcf per day for 2001. The overall increase in natural gas deliveries was due to an increase in Canada of 22% to 154 MMcf per day in 2002 and an increase in Trinidad of 17% to 135 MMcf per day in 2002. The higher production in 2002 was attributable to drilling activities and strategic property acquisitions in Canada, and the commencement of production from the U(a) Block in Trinidad. This increase was partially offset by the overall decrease in production in the United States of 7% or 45 MMcf per day.

Wellhead crude oil and condensate revenues decreased approximately $25 million due primarily to a decline in domestic crude oil and condensate deliveries with essentially flat wellhead crude oil and condensate prices. The composite average wellhead crude oil and condensate price for 2002 was $24.56 per barrel compared to $24.83 per barrel for 2001.

Crude oil and condensate deliveries decreased 10% to 23.3 MBbl per day for 2002 compared to 25.8 MBbl per day in 2001. The decrease in volumes was primarily due to decreased crude oil and condensate production in certain areas in the United States as a result of a natural decline in production. This natural decline in production was partially offset by increased production in Trinidad due to the commencement of production from the U(a) Block, and drilling activities and strategic property acquisitions in Canada.

Natural gas liquids revenues were $6 million lower in 2002 than in 2001 primarily due to a decrease in prices of 17% and a decrease in deliveries of 8%.

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. During 2001, EOG recognized gains on mark-to-market commodity derivative contracts of $98 million, of which $67 million were realized gains which were netted against a $5 million collar premium payment.

Other marketing activities associated with sales and purchases of natural gas increased net operating revenues by $37 million and $16 million in 2002 and 2001, respectively.

Operating and Other Expenses

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	$ 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, depreciation, depletion and amortization (DD&A), general and administrative (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 operating activities 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 Statement of Financial Accounting Standards (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 decreases in 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 revenue 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 geoscience 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.

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), offset by net tax benefit associated with the Canadian tax law change ($14 million).

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.

2002 compared to 2001. During 2002, operating expenses of $914 million were approximately $66 million lower than the $980 million incurred in 2001. The following table presents the costs per Mcfe for the years ended December 31:

	2002	2001
Lease and Well	$ 0.45	$ 0.44
DD&A	1.00	0.98
G&A	0.22	0.20
Taxes Other than Income	0.18	0.24
Interest Expense, Net	0.15	0.11
Total Per-Unit Costs	$ 2.00	$ 1.97

The changes in per-unit lease and well, DD&A, G&A, taxes other than income and net interest expense rates for 2002 compared to 2001 are due primarily to the reasons set forth below.

Lease and well expenses increased $4 million to $179 million compared to a year ago primarily due to continually expanding operations and increases in production activity in Canada, partially offset by fewer workovers in the Gulf of Mexico.

DD&A expenses increased $6 million to $398 million primarily due to increased activity in Canada and higher per unit costs related to certain fields in the United States.

G&A expenses increased $9 million to $89 million primarily due to the settlement of litigation in the second quarter, increased insurance expense and expanded operations.

Taxes other than income decreased $23 million to $72 million as compared to 2001 due to decreased wellhead revenue in North America resulting in lower production taxes and decreased ad valorem taxes.

The increase in net interest expense of $15 million for 2002 as compared to 2001 is primarily due to higher average debt balance for the year of 2002 and the one-time close-out fees associated with the completion of the Section 29 (Tight Gas Sands Federal Income Tax Credits) financing begun in 1999.

Exploration costs of $60 million were $7 million lower than a year ago primarily due to decreased geological and geoscience expenditures.

Dry hole costs of $47 million decreased $25 million from 2001.

Impairments decreased $11 million to $68 million primarily as a result of improved value-to-cost relationship on a field by field basis and decreased amortization of unproved leases in 2002.

Income tax provision decreased approximately $200 million for 2002 as compared to 2001 primarily as a result of a lower pre-tax income in 2002 and a reduction in the overall foreign effective tax rate.

CAPITAL RESOURCES AND LIQUIDITY

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2003 included funds generated from operations and funds from new borrowings. Primary cash outflows included funds used in operations, exploration and development expenditures, oil and gas property acquisitions, repayment of debt, common stock repurchases and dividends.

2003 compared to 2002. Net operating cash inflows of $1,320 million in 2003 increased approximately $652 million as compared to 2002 primarily reflecting an increase in operating revenues of $650 million and favorable changes in working capital and other liabilities of $115 million, partially offset by an increase in cash operating expenses of $132 million.

Net investing cash outflows of approximately $1,269 million in 2003 increased by $396 million as compared to 2002 due primarily to increased exploration and development expenditures of $501 million, which includes $366 million related to two Canadian asset purchases as mentioned below in the Capital Expenditures discussion, partially offset by favorable changes in working capital of $81 million related to investing activities and a decrease in equity investment of $15 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.

2002 compared to 2001. Net operating cash flows of $669 million in 2002 decreased approximately $529 million as compared to 2001 primarily due to lower average natural gas and liquids prices, partially offset by lower cash operating expenses and lower current income taxes. Changes in working capital and other liabilities decreased operating cash flows by $145 million as compared to 2001 primarily due to changes in accounts receivable, accrued royalties payable and accrued production taxes caused by fluctuation of commodity prices at each yearend.

Net investing cash outflows of $873 million in 2002 decreased by $216 million as compared to 2001 due primarily to decreased exploration and development expenditures of $292 million (including producing property acquisitions), partially offset by increased uses of working capital related to investing activities and increased equity investments.

Cash provided by financing activities in 2002 was $211 million as compared to cash used of $127 million in 2001. Financing activities in 2002 included funds from new borrowings of $289 million, common stock repurchases of $63 million, dividend payments of $29 million and proceeds from stock options exercised of $17 million. New borrowings included $120 million of commercial paper borrowings and $250 million of promissory note issuances, partially offset by a decrease in uncommitted line of credit borrowings of $81 million.

Exploration and Development Expenditures

The table below sets out components of exploration and development expenditures for the years ended December 31, 2003, 2002 and 2001, along with the total budgeted for 2004, excluding acquisitions (in millions):

	Actual			Budgeted 2004
Expenditure Category	2003	2002	2001	(excluding acquisitions)
Capital				
Drilling and Facilities	$ 731	$ 595	$ 722	
Leasehold Acquisitions	59	39	76	
Producing Property Acquisitions	405	71	168	
Capitalized Interest	9	9	9	
Subtotal	1,204	714	975	
Exploration Costs	76	60	67	
Dry Hole Costs	41	47	71	
Subtotal	1,321	821	1,113	Approximately $1,100
Asset Retirement Costs(1)	12	-	-	
Deferred Income Tax Gross Up	-	15	50	
Total(2)	$1,333	$ 836	$ 1,163	

(1) 2003 Asset Retirement Costs do not include the cumulative effect of adoption and are netted with gains recognized upon settlement of asset retirement obligations of $1 million.

(2) Pro forma total expenditures for 2002 and 2001 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.

Total exploration and development expenditures of $1,333 million increased $497 million in 2003 as compared to 2002 due primarily to the two property acquisitions by a Canadian subsidiary of EOG, as described below, and increased exploration and development activities across EOG. Included in 2003 expenditures are $652 million in development, $405 million in property acquisitions and $266 million in exploration.

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 has 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.

Derivative Transactions

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. (See Note 12 to the Consolidated Financial Statements.)

Presented below is a summary of EOG's 2004 natural gas financial collar contracts and natural gas and crude oil financial price swap contracts as of February 24, 2004, with prices expressed in $/MMBtu and in $/Bbl, as applicable, and notional volumes in MMBtud and in Bbld, as applicable. 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, 2003. EOG accounts for these collar and swap contracts using mark-to-market accounting.

	Natural Gas Financial Collar Contracts					Financial Price Swap Contracts			
		Floor Price		Ceiling Price		Natural Gas		Crude Oil	
Month[1]	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (Bbld)	Weighted Average Price ($/Bbl)
Jan	330,000	$5.06 - 5.88	$5.38	$5.86 - 6.69	$6.29	30,000	$5.57	4,000	$30.61
Feb	330,000	5.02 - 5.78	5.31	5.82 - 6.62	6.24	30,000	5.50	4,000	30.12
Mar	330,000	4.93 - 5.53	5.16	5.73 - 6.40	6.10	30,000	5.37	4,000	29.58
Apr	375,000	4.47 - 4.71	4.59	4.93 - 5.30	5.13	30,000	4.89	4,000	29.08
May	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	4,000	28.66
Jun	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	4,000	28.27
Jul	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	3,000	27.91
Aug	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	2,000	28.11
Sep	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.78	-	-
Oct	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	-	-

(1) The collar contracts for January 2004 to March 2004 were purchased at a total premium of $3 million or $0.10 per MMBtu. The collar contracts for April 2004 to October 2004 were purchased without a premium.

Financing

EOG's long-term debt-to-total capitalization ratio was 33.3% as of December 31, 2003 compared to 40.6% as of December 31, 2002.

During 2003, total long-term debt decreased $36 million to $1,109 million (see Note 2 to the Consolidated Financial Statements). The estimated fair value of EOG's long-term debt at December 31, 2003 and 2002 was $1,175 million and $1,225 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, 2003, a 1% decline in interest rates would result in a $51 million increase in the estimated fair value of the fixed rate obligations (see Note 12 to the Consolidated Financial Statements).

During 2003 and 2002, EOG utilized primarily commercial paper and committed bank loans 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 2003 was $244 million and the amount outstanding at yearend was $98 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.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2003 (in thousands):

Contractual Obligations[1]	Total	2004	2005 - 2007	2008 - 2009	2010 & beyond
Long-Term Debt[2]	$ 1,108,872	$ 198,050	$ 376,870	$ 173,952	$ 360,000
Non-cancelable Operating Leases	54,650	18,187	25,954	3,898	6,611
Drilling Rig Commitments	2,364	1,033	998	333	-
Pipeline Transportation Service Commitments[3]	45,702	13,615	25,811	3,666	2,610
Total Contractual Obligations	$ 1,211,588	$ 230,885	$ 429,633	$ 181,849	$ 369,221

(1) See Notes 2 and 8 to the Consolidated Financial Statements.

(2) Commercial paper and the 6.50% Notes due 2004 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, 2003. Management does not believe that any future changes in these rates before the expiration dates of these commitments will have a materially adverse effect on the financial condition or results of operations of EOG.

Shelf Registration

As of February 24, 2004, 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 2003, 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 2003 was the Canadian Dollar. While the strengthening of the Canadian Dollar in 2003 impacted both the revenues and expenses recorded on the income statements of EOG's Canadian subsidiaries, its impacts on these 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 will implement measures to protect against the foreign currency exchange rate risk if needed.

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 North America natural gas and crude oil price trends, and there remains a rather wide divergence in the opinions held by some in the industry. This divergence in opinion is caused by various factors including current economic conditions, improvements in the technology used in drilling and completing crude oil and natural gas wells, fluctuations in the availability and utilization of natural gas storage capacity and ever-changing weather patterns. However, the increasing recognition of natural gas as a more environmentally friendly source of energy could 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 natural rate of production decline in North America, the level of North American rig activity and the level of LNG imports as well as prices of competing fuels, including oil.

Marketing companies have played an important role in the North American 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 North America. However, in order to diversify its overall asset portfolio and as a result of its overall success realized in Trinidad, EOG anticipates expending a portion of its available funds in the further development of opportunities outside North America. In addition, EOG expects to conduct exploratory activity in other areas outside of North America, including the United Kingdom North Sea, and will continue to evaluate the potential for involvement in other exploitation type opportunities. Budgeted 2004 exploration and development expenditures, excluding acquisitions, are approximately $1.1 billion, addressing the continuing uncertainty with regard to the future of the North America natural gas and crude oil and condensate price environment. Budgeted expenditures for 2004 are structured to maintain the flexibility necessary under EOG's strategy of funding North America exploration, exploitation, development and acquisition activities primarily from available internally generated cash flow.

The level of exploration and development expenditures may vary in 2004 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 2004 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, may affect EOG's operations and costs as a result of their effect on natural gas and crude oil exploration, exploitation, development and production operations. 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. EOG also has acquired or merged with companies that own and operate oil and gas properties. Any obligations or liabilities of these companies under environmental laws would continue as liabilities of the acquired company, or of EOG in the event of a merger, even if the obligations or liabilities resulted from actions that took place before the acquisition or merger. Compliance with such laws and regulations 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 by reason of environmental laws and regulations. However, 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. In this regard, EOG has been named as a potentially responsible party in certain proceedings initiated pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act and may be named as a potentially responsible party in other similar proceedings in the future. It is not anticipated that the costs incurred by EOG in connection with the presently pending proceedings will, individually or in the aggregate, have a materially adverse effect on the financial condition or results of operations of EOG.

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, with secondary verification from third-party experts, D&M, 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.

Periodically, or 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.

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.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report 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; 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.

REPORTS OF INDEPENDENT PUBLIC ACCOUNTANTS

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. (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. The consolidated financial statements of EOG Resources, Inc. for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those consolidated financial statements in their report dated February 21, 2002.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," on January 1, 2003.

Deloitte & Touche LLP

Houston, Texas
February 23, 2004

EOG dismissed Arthur Andersen LLP on February 27, 2002 and subsequently engaged Deloitte & Touche LLP as its independent auditors. The predecessor auditor's report appearing below is a copy of Arthur Andersen's previously issued report dated February 21, 2002. Since EOG is unable to obtain a current manually signed audit report, a copy of Arthur Andersen's most recent signed and dated report has been included to satisfy filing requirements, as permitted under Rule 2-02(e) of Regulation S-X. The only information in the financial statements and the related footnotes included in this Annual Report that is referred to in the report of Arthur Andersen LLP is the information included in the accompanying Consolidated Statements of Income and Comprehensive Income, Consolidated Statements of Shareholders' Equity, Consolidated Statements of Cash Flows and the related footnotes for the year ended December 31, 2001.

To EOG Resources, Inc.:

We have audited the accompanying consolidated balance sheets of EOG Resources, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, 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, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of EOG Resources, Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Houston, Texas
February 21, 2002

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 accounting principles generally accepted in the United States and, accordingly, include some amounts that are based on the best estimates and judgments of management.

Deloitte & Touche LLP, independent public accountants, was engaged to audit the consolidated financial statements of EOG and 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. Their audit was made in accordance with auditing standards generally accepted in the United States of America 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 believes that all representations made to Deloitte & Touche LLP during the audit were valid and appropriate.

The system of internal controls of EOG is designed to provide reasonable assurance as to the reliability of financial statements and the protection of assets from unauthorized acquisition, use or disposition. This system includes, but is not limited to, written policies and guidelines including a published code for the conduct of business affairs, conflicts of interest and compliance with laws regarding antitrust, antiboycott and foreign corrupt practices policies, the careful selection and training of qualified personnel, and a documented organizational structure outlining the separation of responsibilities among management representatives and staff groups.

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. It should be recognized that there are inherent limitations to the effectiveness of any system of internal control, including the possibility of human error and circumvention or override. Accordingly, even an effective system can provide only reasonable assurance with respect to the preparation of reliable financial statements and safeguarding of assets. Furthermore, the effectiveness of an internal control system can change with circumstances.

It is management's opinion that, considering the criteria for effective internal control over financial reporting and safeguarding of assets which consists of interrelated components including the control environment, risk assessment process, control activities, information and communication systems, and monitoring, EOG maintained an effective system of internal control as to the reliability of financial statements and the protection of assets against unauthorized acquisition, use or disposition during the year ended December 31, 2003.

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

Edmund P. Segner, III
President and Chief of Staff

Timothy K. Driggers
Vice President and Chief Accounting Officer

Houston, Texas
February 23, 2004

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(In Thousands, Except Per Share Amounts)	Year Ended December 31, 2003	2002	2001
Net Operating Revenues			
Natural Gas	$1,537,352	$ 915,129	$1,298,102
Crude Oil, Condensate and Natural Gas Liquids	283,042	227,309	258,101
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	(80,414)	(48,508)	97,750
Other, Net	4,695	752	1,769
Total	1,744,675	1,094,682	1,655,722
Operating Expenses			
Lease and Well	212,601	179,429	175,446
Exploration Costs	76,358	60,228	67,467
Dry Hole Costs	41,156	46,749	71,360
Impairments	89,133	68,430	79,156
Depreciation, Depletion and Amortization	441,843	398,036	392,399
General and Administrative	100,403	88,952	79,963
Taxes Other Than Income	85,867	71,881	95,333
Charges Associated with Enron Bankruptcy	-	-	19,211
Total	1,047,361	913,705	980,335
Operating Income	697,314	180,977	675,387
Other Income (Expense), Net	15,273	(1,651)	1,168
Income Before Interest Expense and Income Taxes	712,587	179,326	676,555
Interest Expense			
Incurred	67,252	68,641	53,756
Capitalized	(8,541)	(8,987)	(8,646)
Net Interest Expense	58,711	59,654	45,110
Income Before Income Taxes	653,876	119,672	631,445
Income Tax Provision	216,600	32,499	232,829
Net Income Before Cumulative Effect of Change in Accounting Principle	437,276	87,173	398,616
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(7,131)	-	-
Net Income	430,145	87,173	398,616
Preferred Stock Dividends	11,032	11,032	10,994
Net Income Available to Common	$ 419,113	$ 76,141	$ 387,622
Net Income Per Share Available to Common			
Basic			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 3.72	$ 0.66	$ 3.35
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-
Net Income Per Share Available to Common	$ 3.66	$ 0.66	$ 3.35
Diluted			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 3.66	$ 0.65	$ 3.30
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-
Net Income Per Share Available to Common	$ 3.60	$ 0.65	$ 3.30
Average Number of Common Shares			
Basic	114,597	115,335	115,765
Diluted	116,519	117,245	117,488
Comprehensive Income			
Net Income	$ 430,145	$ 87,173	$ 398,616
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustment	123,811	4,315	(22,044)
Available-for-Sale Security Transactions	-	926	(1,318)
Comprehensive Income	$ 553,956	$ 92,414	$ 375,254

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

CONSOLIDATED BALANCE SHEETS

(In Thousands, Except Share Data)	At December 31, 2003	2002
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 4,443	$ 9,848
Accounts Receivable, Net	295,118	259,308
Inventories	21,922	18,928
Income Taxes Receivable	7,976	67,090
Deferred Income Taxes	31,548	12,925
Other	35,007	26,255
Total	396,014	394,354
Oil and Gas Properties (Successful Efforts Method)	8,189,062	6,750,095
Less: Accumulated Depreciation, Depletion and Amortization	(3,940,145)	(3,428,547)
Net Oil and Gas Properties	4,248,917	3,321,548
Other Assets	104,084	97,666
Total Assets	$ 4,749,015	$ 3,813,568
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 282,379	$ 201,931
Accrued Taxes Payable	33,276	22,732
Dividends Payable	6,175	5,007
Liabilities from Price Risk Management Activities	37,779	5,939
Deferred Income Taxes	73,611	39,634
Other	43,299	40,304
Total	476,519	315,547
Long-Term Debt	1,108,872	1,145,132
Other Liabilities	171,115	59,180
Deferred Income Taxes	769,128	621,314
Shareholders' Equity		
Preferred Stock, $.01 Par, 10,000,000 Shares Authorized:		
Series B, 100,000 Shares Issued, Cumulative, $100,000,000 Liquidation Preference	98,589	98,352
Series D, 500 Shares Issued, Cumulative, $50,000,000 Liquidation Preference	49,827	49,647
Common Stock, $.01 Par, 320,000,000 Shares Authorized and 124,730,000 Shares Issued	201,247	201,247
Additional Paid in Capital	1,625	-
Unearned Compensation	(23,473)	(15,033)
Accumulated Other Comprehensive Income (Loss)	73,934	(49,877)
Retained Earnings	2,121,214	1,723,948
Common Stock Held in Treasury, 8,819,600 Shares at December 31, 2003 and 10,009,740 Shares at December 31, 2002	(299,582)	(335,889)
Total Shareholders' Equity	2,223,381	1,672,395
Total Liabilities and Shareholders' Equity	$ 4,749,015	$ 3,813,568

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

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, 2000	$ 147,164	$ 201,247	$ 4,221	$ (3,756)	$ (31,756)	$ 1,301,067	$ (237,262)	$ 1,380,925
Net Income	-	-	-	-	-	398,616	-	398,616
Amortization of Preferred Stock Discount	418	-	-	-	-	(418)	-	-
Preferred Stock Dividends Paid/Declared	-	-	-	-	-	(10,576)	-	(10,576)
Common Stock Dividends Declared, $.16 Per Share	-	-	-	-	-	(18,523)	-	(18,523)
Translation Adjustment	-	-	-	-	(22,044)	-	-	(22,044)
Unrealized Loss on Available-for-Sale Security	-	-	-	-	(1,318)	-	-	(1,318)
Treasury Stock Purchased	-	-	-	-	-	-	(126,769)	(126,769)
Treasury Stock Issued Under Stock Option Plans	-	-	(19,097)	-	-	(1,458)	50,403	29,848
Treasury Stock Issued Under Employee Stock Purchase Plan	-	-	(104)	-	-	-	1,061	957
Tax Benefits from Stock Options Exercised	-	-	7,332	-	-	-	-	7,332
Restricted Stock and Units	-	-	6,583	(14,467)	-	-	7,884	-
Amortization of Unearned Compensation	-	-	-	3,270	-	-	-	3,270
Equity Derivative Transactions	-	-	1,201	-	-	-	-	1,201
Other	-	-	(136)	-	-	-	(97)	(233)
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 Paid/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	-	-	-	-	-	-	(63,038)	(63,038)
Treasury Stock Issued Under Stock Option Plans	-	-	(9,457)	-	-	(2,402)	28,565	16,706
Treasury Stock Issued Under 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
Other	-	-	-	-	-	-	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 Paid/Declared	-	-	-	-	-	(10,615)	-	(10,615)
Common Stock Dividends Declared, $.18 Per Share	-	-	-	-	-	(21,847)	-	(21,847)
Translation Adjustment	-	-	-	-	123,811	-	-	123,811
Treasury Stock Purchased	-	-	-	-	-	-	(21,295)	(21,295)
Treasury Stock Issued Under Stock Option Plans	-	-	(16,522)	-	-	-	46,379	29,857
Treasury Stock Issued Under Employee Stock Purchase Plan	-	-	84	-	-	-	2,515	2,599
Tax Benefits from Stock Options Exercised	-	-	11,926	-	-	-	-	11,926
Restricted Stock and Units	-	-	6,084	(14,467)	-	-	8,383	-
Amortization of Unearned Compensation	-	-	-	6,027	-	-	-	6,027
Other	-	-	53	-	-	-	325	378
Balance at December 31, 2003	**$ 148,416**	**$ 201,247**	**$ 1,625**	**$ (23,473)**	**$ 73,934**	**$ 2,121,214**	**$ (299,582)**	**$ 2,223,381**

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)	Year Ended December 31, 2003	2002	2001
Cash Flows from Operating Activities			
Reconciliation of Net Income to Net Operating Cash Inflows:			
Net Income	$ 430,145	$ 87,173	$ 398,616
Items Not Requiring Cash			
Depreciation, Depletion and Amortization	441,843	398,036	392,399
Impairments	89,133	68,430	79,156
Deferred Income Taxes	191,726	82,179	164,945
Charges Associated with Enron Bankruptcy	-	-	19,211
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	7,131	-	-
Other, Net	1,033	17,333	10,423
Exploration Costs	76,358	60,228	67,467
Dry Hole Costs	41,156	46,749	71,360
Mark-to-Market Commodity Derivative Contracts			
Total (Gains) Losses	80,414	48,508	(97,750)
Realized Gains (Losses)	(44,870)	(21,136)	66,731
Collar Premium	(3,003)	(1,825)	(4,621)
Tax Benefits from Stock Options Exercised	11,926	5,168	7,332
Other, Net	2,141	(1,978)	(2,292)
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	(36,156)	(61,580)	146,235
Inventories	(2,994)	(57)	(2,248)
Accounts Payable	79,748	(19,012)	(26,949)
Accrued Taxes Payable	8,285	(84,666)	(38,619)
Other Liabilities	(3,387)	7,816	(3,422)
Other, Net	(14,400)	(5,578)	(16,442)
Changes in Components of Working Capital Associated with Investing and Financing Activities	(35,928)	42,782	(34,105)
Net Operating Cash Inflows	1,320,301	668,570	1,197,427
Investing Cash Flows			
Additions to Oil and Gas Properties	(1,204,383)	(714,127)	(974,016)
Exploration Costs	(76,358)	(60,228)	(67,467)
Dry Hole Costs	(41,156)	(46,749)	(71,360)
Proceeds from Sales of Assets	13,480	8,089	8,032
Changes in Components of Working Capital Associated with Investing Activities	37,475	(43,246)	32,405
Other, Net	2,432	(16,277)	(15,649)
Net Investing Cash Outflows	(1,268,510)	(872,538)	(1,088,055)
Financing Cash Flows			
Long-Term Debt Borrowings (Repayments)	(36,260)	289,163	(4,155)
Dividends Paid	(31,294)	(29,152)	(28,580)
Treasury Stock Purchased	(21,295)	(63,038)	(126,769)
Proceeds from Stock Options Exercised	35,138	17,339	30,805
Other, Net	(3,485)	(3,008)	1,687
Net Financing Cash Inflows (Outflows)	(57,196)	211,304	(127,012)
Increase (Decrease) in Cash and Cash Equivalents	(5,405)	7,336	(17,640)
Cash and Cash Equivalents at Beginning of Year	9,848	2,512	20,152
Cash and Cash Equivalents at End of Year	$ 4,443	$ 9,848	$ 2,512

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. If proved commercial reserves are not discovered, such drilling costs are expensed. 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. 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.

EOG accounts for impairments under the provisions of Statement of Financial Accounting Standards (SFAS) No. 144 - "Accounting for the Impairment or Disposal of Long-Lived Assets." Periodically, or 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.

Natural gas and liquids revenues are recorded when production is delivered. 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. 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 2001, 2002 and 2003, 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 12).

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 6).

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 9 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 (see Note 7).

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.

In November 2002, the FASB released its Interpretation No. 45 - "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 requires a company, when serving as a guarantor, to disclose its obligations and/or recognize the liability associated with the guarantee. The initial recognition and measurement provisions of this Interpretation are applicable to guarantees issued or modified after December 31, 2002 on a prospective basis. Disclosure is effective for financial statements of interim or annual periods ending after December 15, 2002. EOG has identified one instance where it acts as a co-guarantor in a loan agreement between a bank and a school in Trinidad. The maximum exposure for EOG is US $1 million. EOG deems the amount immaterial. The guarantee does not require measurement and recognition under FIN 45.

In December 2002, the FASB issued SFAS No. 148 - "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123." This statement provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation, along with the requirement of disclosure in both annual and interim financial statements about the method used and effect on reported results (see Note 7). Subsequently, at the April 22, 2003 FASB meeting, the FASB decided to require all companies to expense the value of employee stock options. Companies will be required to measure the cost according to the fair value of the options under a method yet to be determined. On October 1, 2003, the FASB set a goal of completing its deliberations and issuing a final statement in the second half of 2004. EOG continues to monitor the developments in this area as details of the implementation of the decision emerge.

In January 2003, the FASB released its Interpretation No. 46 - "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" (FIN 46). FIN 46 requires a company to consolidate a variable interest entity (VIE) if the company has a variable interest (or combination of variable interests) that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur, or both. Since EOG does not own any interest in a VIE, the release of FIN 46 does not have any effect on its financial position or results of operations.

During the third quarter of 2003, the Securities and Exchange Commission (SEC) has 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." However, the SEC is not requiring all oil and gas producing companies to apply this classification or the disclosure requirements of intangible assets. Currently, EOG classifies the cost of oil and gas mineral rights as oil and gas properties and believes that this is consistent with oil and gas accounting and industry practice. The FASB has been asked to address this issue. If the FASB determines that the reclassification is required, EOG would reclassify these costs from oil and gas properties to intangible assets on the balance sheet. There would be no effect on the statement of income or cash flows.

In December 2003, the FASB issued a revision to SFAS No. 132 - "Employers' Disclosures about Pensions and Other Postretirement Benefits." The revised SFAS No. 132 retains the disclosures required by the original SFAS No. 132 and requires additional disclosures on the types of plan assets, investment strategy, measurement dates, plan obligations, cash flows and components of net periodic benefit cost recognized during interim periods. This revision to SFAS No. 132 does not have any effect on EOG's financial position or results of operations. EOG has modified its existing disclosure on benefit plans to incorporate this revision (see Note 7).

In January 2004, the FASB released its FASB Staff Position No. 106-1 - "Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-1), which allows a company to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug Improvement Act of 2003 (Act). While EOG is aware of the Act, any measures of the Accounting for Postretirement Benefits Other than Pensions or net periodic postretirement benefit cost in the financial statements and accompanying Footnote 7 below, do not reflect the effects of the Act on the plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require the company to change previously reported information.

2. LONG-TERM DEBT

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

	2003	2002
Commercial Paper	$ 98,050	$ 120,000
Uncommitted Credit Facilities	-	14,310
Senior Unsecured Term Loan		
Facility due 2005	150,000	150,000
6.50% Notes due 2004	100,000	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
Total	$1,108,872	$1,145,132

During 2003 and 2002, EOG utilized commercial paper and short-term funding from uncommitted credit facilities, 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. 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 bankers' 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, 2003.

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. The applicable interest rate for this Facility was 1.88% at December 31, 2003.

The 6.00% to 6.70% Notes due 2004 to 2028 were issued through public offerings and have effective interest rates of 6.14% to 6.83%. 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 1.28% for 2003.

At December 31, 2003, the aggregate annual maturities of long-term debt were $100 million for 2004, $150 million for 2005, $127 million in 2006, $100 million for 2007 and $174 million for 2008. The 6.50% Notes due 2004 are classified as long-term debt based on EOG's intent and ability to ultimately refinance such amounts with other long-term debt.

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 24, 2004, 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, 2003 and 2002, EOG had $1,109 million and $1,145 million, respectively, of long-term debt, which had fair values of approximately $1,175 million and $1,225 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

EOG purchases its common stock from time to time in the open market to be held in treasury for the purpose of, but not limited to, 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, 2003, 6,386,200 shares remain available for repurchases under this authorization.

During the second quarter of 2001, EOG sold put options for $1.2 million obligating EOG to purchase up to 0.6 million shares of its common stock at an average price of $33.42 per share. These options expired unexercised in December 2001. EOG had written one million put options which were outstanding at December 31, 2000. The strike price of these options was $18.00 per share, and they expired unexercised in April 2001.

The following summarizes shares of common stock outstanding (in thousands):

	Common Shares		
	2003	2002	2001
Outstanding at January 1 . . .	114,720	115,452	116,904
Repurchased	(531)	(1,700)	(3,281)
Issued Pursuant to Stock Options and Stock Plans . .	1,721	968	1,829
Outstanding at December 31	115,910	114,720	115,452

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. 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 December 10, 2002, the Rights Agreement was amended to create an exception to the definition of Acquiring Person to permit a qualified institutional investor to beneficially own 10% or more but less than 15% 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 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; and (iii) the institutional investor does not beneficially own 15% or more of EOG's common stock then outstanding.

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.

4. ENRON CORP. BANKRUPTCY

In December 2001, Enron Corp. and certain of its affiliates, including Enron North America Corp., filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. EOG recorded $19 million in charges associated with the Enron bankruptcies in the fourth quarter of 2001 related to certain contracts with Enron affiliates, including 2001 and 2002 natural gas and crude oil derivative contracts. Based on EOG's review of all matters related to Enron Corp. and its affiliates, EOG believes that Enron Corp.'s Chapter 11 proceedings will not have a material adverse effect on EOG's financial position.

5. OTHER INCOME (EXPENSE), NET

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.

6. INCOME TAXES

The principal components of EOG's net deferred income tax liability at December 31, 2003 and 2002 were as follows (in thousands):

	2003	2002
Current Deferred Income Tax Assets		
Commodity Hedging Contracts	$ 9,739	$ (1,688)
Deferred Compensation Plans	4,994	3,801
Net Operating Loss	5,225	-
Other	11,590	10,812
Total Current Deferred Income Tax Assets	31,548	12,925
Current Deferred Income Tax Liabilities		
Timing Differences Associated With Different Yearends in Foreign Jurisdictions	73,611	39,634
Total Net Current Deferred Income Tax Liability	$ 42,063	$ 26,709

	2003	2002
Noncurrent Deferred Income Tax Assets (included in Other Assets)		
Foreign Net Operating Loss Carryforward	$ 3,688	$ -
Noncurrent Deferred Income Tax Assets		
Non-Producing Leasehold Costs	$ 36,154	$ 29,574
Seismic Costs Capitalized for Tax	21,365	18,657
Alternative Minimum Tax Credit Carryforward	3,869	20,200
Other	20,124	12,589
Total Noncurrent Deferred Income Tax Assets	81,512	81,020
Noncurrent Deferred Income Tax Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	837,189	691,555
Capitalized Interest	13,451	10,779
Total Noncurrent Deferred Income Tax Liabilities	850,640	702,334
Total Net Noncurrent Deferred Income Tax Liability	$ 769,128	$ 621,314
Total Net Deferred Income Tax Liability	$ 807,503	$ 648,023

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

	2003	2002	2001
United States	$442,109	$ 37,354	$488,741
Foreign	211,767	82,318	142,704
Total	$653,876	$119,672	$631,445

Total income tax provision was as follows (in thousands):

	2003	2002	2001
Current:			
Federal	$ 3,844	$ (61,013)	$ 36,737
State	880	(5,130)	5,475
Foreign	20,150	16,463	25,672
Total	24,874	(49,680)	67,884
Deferred:			
Federal	151,389	57,232	131,127
State	4,052	(358)	10,411
Foreign	36,285	25,305	23,407
Total	191,726	82,179	164,945
Income Tax Provision	$216,600	$ 32,499	$232,829

The differences between income taxes computed at the U.S. federal statutory tax rate and EOG's effective rate were as follows:

	2003	2002	2001
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	0.73	0.22	1.64
Income Tax Provision Related to Foreign Operations	(0.05)	(3.54)	0.36
Change in Canadian Federal Tax Rate	(2.16)	-	-
Tight Gas Sands Federal Income Tax Credits	-	(3.57)	(0.83)
Other	(0.40)	(0.95)	0.70
Effective Income Tax Rate	33.12%	27.16%	36.87%

EOG's foreign subsidiaries' undistributed earnings of approximately $722 million at December 31, 2003 are considered to be indefinitely invested outside the U.S. and, accordingly, no U.S. federal 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 U.S. 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 will not expire until 2022. EOG expects the entire remaining net operating loss to be utilized in 2004.

A foreign net operating loss of $9 million was incurred during 2003. These losses will be carried forward indefinitely until they are utilized.

EOG has an alternative minimum tax (AMT) credit carryforward of $4 million which can be used to offset regular income taxes payable in future years. The AMT credit carryforward has an indefinite carryforward period.

7. EMPLOYEE BENEFIT PLANS

Pension Plans

EOG has defined contribution pension and savings plans in place for most of its employees in the United States. EOG's contributions to these plans are based on various percentages of compensation, and in some instances, are based upon the amount of the employees' contributions to the plan. For 2003, 2002 and 2001, the contributions to these plans amounted to approximately $8.2 million, $8.0 million and $6.5 million, respectively.

In addition, EOG's Canadian subsidiary maintains a non-contributory defined contribution pension plan and a matched savings plan and EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. These plans are available to most employees of the Canadian and Trinidadian subsidiaries and activity related to these plans was less than $1 million combined for 2003, which is deemed immaterial relative to EOG's operations.

Postretirement Plan

During 2000, EOG adopted postretirement medical and dental benefits 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 (in thousands):

	As of December 31,		
	2003	2002	2001
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	$ 1,875	$ 2,021	$ 1,526
Service Cost	175	139	192
Interest Cost	131	115	134
Plan Participants' Contributions	64	58	34
Amendments	773	-	-
Benefits Paid	(102)	(95)	(63)
Actuarial (Gain) Loss	95	(363)	198
Benefit Obligation at Yearend	$ 3,011	$ 1,875	$ 2,021
Change in Plan Asset			
Fair Value of Plan Asset at Beginning of Year	$ -	$ -	$ -
Employer Contributions	38	37	29
Plan Participants' Contributions	64	58	34
Benefits Paid	(102)	(95)	(63)
Fair Value of Plan Asset at End of Year	$ -	$ -	$ -
Reconciliation of Funded Status to Balance Sheet			
Funded Status	$ 3,011	$ 1,875	$ 2,021
Unrecognized Net Actuarial Gain (Loss)	(64)	35	(327)
Unrecognized Prior Service (Cost) Benefit	(1,647)	(948)	(1,024)
Accrued Benefit Cost at Yearend	$ 1,300	$ 962	$ 670
Components of Net Periodic Benefit Cost			
Service Cost	$ 175	$ 139	$ 192
Interest Cost	131	115	134
Amortization of Prior Service Cost	75	75	75
Recognized Net Actuarial Loss (Gain)	-	(1)	8
Net Periodic Benefit Cost	$ 381	$ 328	$ 409

Weighted-average discount rate assumptions used in the determination of benefit obligations at December 31, 2003, 2002 and 2001 were 6.15%, 6.40% and 7.00%, respectively. Weighted-average discount rate assumptions used in the determination of net periodic benefit cost for years ended December 31, 2003, 2002 and 2001 were 6.40%, 7.00% and 7.25%, 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
2004	$ 57
2005	68
2006	81
2007	92
2008	104
2009 - 2013	855

Postretirement health care trend rates have zero effect on the amounts reported for the postretirement health care plan for both 2003 and 2002. 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. At December 31, 2003, the total number of shares authorized for grant from the Plans was 27,445,000 shares.

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.

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

	2003		2002		2001	
	Options	Average Grant Price	Options	Average Grant Price	Options	Average Grant Price
Outstanding at January 1	7,842	$ 27.31	7,013	$ 24.69	7,056	$ 20.70
Granted	1,515	39.13	1,809	33.82	1,631	36.63
Exercised	(1,485)	22.73	(868)	19.90	(1,563)	19.18
Forfeited	(121)	34.74	(112)	27.64	(111)	23.84
Outstanding at December 31	7,751	30.38	7,842	27.31	7,013	24.69
Options Exercisable at December 31	4,933	27.03	5,041	23.96	4,034	22.04
Available for Future Grant	1,178		2,932		4,531	
Average Fair Value of Options Granted During Year	$ 16.55		$ 14.79		$ 16.76	

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 2003, 2002 and 2001, respectively: (1) dividend yield of 0.4%, 0.4% and 0.5%, (2) expected volatility of 43%, 45% and 43%, (3) risk-free interest rate of 3.4%, 3.7% and 4.6% and (4) expected life of 5.2 years, 5.3 years and 6.0 years.

The following table summarizes certain information for the options outstanding at December 31, 2003 (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
$13.00 to $17.99	892	4	$14.59	887	$14.58
18.00 to 22.99	1,370	4	20.06	1,369	20.06
23.00 to 28.99	198	3	24.33	195	24.27
29.00 to 33.99	2,351	8	33.25	1,276	33.04
34.00 to 39.99	2,568	9	37.27	929	36.37
40.00 to 54.99	372	7	43.86	277	44.19
	7,751	7	30.38	**4,933**	27.03

EOG's pro forma net income and net income per share of common stock for 2003, 2002 and 2001, had compensation costs been recorded in accordance with SFAS No. 123, are presented below (in millions, except per share data):

	Year Ended December 31,		
	2003	2002	2001
Net Income Available to Common - As Reported	$ 419.1	$ 76.1	$ 387.6
Deduct: Total stock-based employee compensation expense	(13.9)	(13.7)	(11.9)
Net Income Available to Common - Pro Forma	$ 405.2	$ 62.4	$ 375.7
Net Income per Share Available to Common			
Basic - As Reported	$ 3.66	$ 0.66	$ 3.35
Basic - Pro Forma	$ 3.54	$ 0.54	$ 3.25
Diluted - As Reported	$ 3.60	$ 0.65	$ 3.30
Diluted - Pro Forma	$ 3.48	$ 0.53	$ 3.20

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.

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 (shares and units in thousands):

	Restricted Shares and Units		
	2003	2002	2001
Outstanding at January 1	775	632	309
Granted	372	158	353
Released	(103)	(10)	(15)
Forfeited or Expired	(18)	(5)	(15)
Outstanding at December 31	1,026	775	632
Average Fair Value of Shares Granted During Year	$ 40.43	$ 32.56	$ 42.08

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 2003, 2002 and 2001 was $6.0 million, $4.9 million and $3.3 million, respectively.

Employee Stock Purchase Plan. During 2001, EOG implemented an Employee Stock Purchase Plan (ESPP) 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, 2003, 324,362 common shares remained available for issuance under the plan. During 2003, approximately 410 employees participated in the plan and 74,094 common shares were purchased at an aggregate price of $2.6 million. During 2002, approximately 350 employees participated in the plan and 69,243 common shares were purchased at an aggregate price of $2.3 million. During 2001, approximately 300 employees participated in the plan and 32,301 common shares were purchased at an aggregate price of $1.0 million.

Treasury Shares. During 2003, 2002 and 2001, EOG repurchased 531,000, 1,700,000 and 3,281,000 of its common shares, respectively. Approximately 531,000, 968,000 and 1,829,000 of these common shares were repurchased during 2003, 2002 and 2001, respectively, to offset the dilution resulting from shares issued under the EOG employee stock plans. The difference between the cost of the treasury shares and the exercise price of the options, net of federal income tax benefit of $11.9 million, $5.2 million and $7.3 million, for the years 2003, 2002 and 2001, 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 retained earnings thereafter.

8. COMMITMENTS AND CONTINGENCIES

Letters Of Credit. At December 31, 2003 and 2002, EOG had standby letters of credit and guarantees outstanding totaling approximately $266 million and $234 million, respectively; however, of these amounts, $220 million represents guarantees of subsidiary indebtedness included under Note 2 "Long-Term Debt."

Minimum Commitments. At December 31, 2003, total minimum commitments from long-term non-cancelable operating leases, drilling rig commitments and pipeline transportation service commitments, based on current transportation rates and the Canadian currency exchange rate at December 31, 2003, are as follows (in thousands):

	Total Minimum Commitments
2004	$ 32,835
2005 - 2007	52,763
2008 - 2009	7,897
2010 and beyond	9,221
	$ 102,716

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2012. Rental expenses associated with these leases amounted to $22 million, $21 million and $20 million for 2003, 2002 and 2001, respectively.

Contingencies. EOG and numerous other companies in the natural gas industry are named as defendants in various lawsuits alleging violations of the Civil False Claims Act. These lawsuits have been consolidated for pre-trial proceedings in the United States District Court for the District of Wyoming. The plaintiffs contend that defendants have underpaid royalties on natural gas and natural gas liquids produced on federal and Indian lands through the use of below-market prices, improper deductions, improper measurement techniques and transactions with affiliated companies. Plaintiffs allege that the royalties paid by defendants were lower than the royalties required to be paid under federal regulations and that the forms filed by defendants with the Minerals Management Service reporting these royalty payments were false, thereby violating the Civil False Claims Act. The United States has intervened in certain of the cases as to some of the defendants, but has not intervened as to EOG. The plaintiff in one of the two lawsuits in which EOG is involved dismissed EOG from that case without prejudice. Based on EOG's present understanding of the remaining case in which it is a defendant, EOG believes that it has substantial defenses to the plaintiff's claims and intends to vigorously assert these defenses. However, if EOG is found to have violated the Civil False Claims Act, EOG could be subject to a variety of sanctions, including treble damages and substantial monetary fines.

There are various other suits and claims against EOG that have arisen in the ordinary course of business. However, management does not believe 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. EOG has been named as a potentially responsible party in certain Comprehensive Environmental Response Compensation and Liability Act proceedings. However, management does not believe that any potential assessments resulting from such proceedings will, individually or in the aggregate, have a material adverse effect on the financial condition of EOG.

9. 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):

	2003	2002	2001
Numerator for basic and diluted earnings per share -			
Net income available to common	$ 419,113	$ 76,141	$ 387,622
Denominator for basic earnings per share -			
Weighted average shares	114,597	115,335	115,765
Potential dilutive common shares -			
Stock options	1,584	1,633	1,453
Restricted stock and units	338	277	270
Denominator for diluted earnings per share -			
Adjusted weighted average shares	116,519	117,245	117,488
Net income per share of common stock			
Basic	$ 3.66	$ 0.66	$ 3.35
Diluted	$ 3.60	$ 0.65	$ 3.30

10. SUPPLEMENTAL CASH FLOW INFORMATION

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

	2003	2002	2001
Interest (net of amount capitalized)	$ 62,472	$ 54,432	$ 45,715
Income taxes	26,330	15,946	106,312

11. 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
2003						
Net Operating Revenues	$ 1,335,145[1]	$ 309,418[1]	$ 100,112	$ -	$ -	$ 1,744,675[1]
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	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[2]	$ 169,106[2]	$ 79,551	$ -	$ 18	$ 1,094,682[2]
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	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
2001						
Net Operating Revenues	$ 1,395,349[2]	$ 191,213[2]	$ 69,140	$ -	$ 20	$ 1,655,722[2]
Depreciation, Depletion and Amortization	348,539	31,821	12,031	-	8	392,399
Operating Income (Loss)	537,549	107,518	36,761	(40)	(6,401)	675,387
Interest Income	1,117	2,244	1,699	-	-	5,060
Other Income (Expense)	(4,123)	77	154	-	-	(3,892)
Interest Expense	45,064	(280)	326	-	-	45,110
Income (Loss) Before Income Taxes	489,479	110,119	38,288	(40)	(6,401)	631,445
Income Tax Provision (Benefit)	187,265	28,438	20,166	432	(3,472)	232,829
Additions to Oil and Gas Properties	729,655	176,101	68,260	-	-	974,016
Total Assets	2,676,182	510,476	227,229	36	121	3,414,044

(1) 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.

(2) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2002 and 2001 that totaled $163 million and $225 million, respectively, of the Consolidated Net Operating Revenues.

12. 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 2003, 2002 and 2001, 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 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. During 2001, EOG recognized gains on mark-to-market commodity derivative contracts of $98 million, of which $67 million were realized gains which were netted against a $5 million collar premium payment.

Presented below is a summary of EOG's 2004 natural gas financial collar contracts and natural gas and crude oil financial price swap contracts as of December 31, 2003 with prices expressed in $/MMBtu and in $/Bbl, as applicable, and notional volumes in MMBtud and in Bbld, as applicable. EOG accounts for these collar and swap contracts using mark-to-market accounting. The total fair value of the natural gas financial collar contracts and natural gas and crude oil financial price swap contracts at December 31, 2003 was a negative $38 million.

	Natural Gas Financial Collar Contracts					Financial Price Swap Contracts			
		Floor Price		Ceiling Price		Natural Gas		Crude Oil	
Month[(1)]	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (Bbld)	Weighted Average Price ($/Bbl)
Jan	330,000	$5.06 - 5.88	$5.38	$5.86 - 6.69	$6.29	30,000	$5.57	4,000	$30.61
Feb	330,000	5.02 - 5.78	5.31	5.82 - 6.62	6.24	30,000	5.50	4,000	30.12
Mar	330,000	4.93 - 5.53	5.16	5.73 - 6.40	6.10	30,000	5.37	4,000	29.58
Apr	375,000	4.47 - 4.71	4.59	4.93 - 5.30	5.13	30,000	4.89	4,000	29.08
May	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	4,000	28.66
Jun	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	4,000	28.27
Jul	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	3,000	27.91
Aug	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	2,000	28.11
Sep	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.78	-	-
Oct	375,000	4.47 - 4.75	4.58	4.93 - 5.19	5.09	30,000	4.80	-	-

(1) The collar contracts for January 2004 to March 2004 were purchased at a total premium of $3 million or $0.10 per MMBtu. The collar contracts for April 2004 to October 2004 were purchased without a premium.

The following table summarizes the estimated fair value of financial instruments and related transactions at December 31, 2003 and 2002 (in millions):

	2003		2002	
	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
Long-Term Debt(2)	$1,109	$1,175	$1,145	$1,225
NYMEX-Related Commodity Market Positions	(38)	(38)	(6)	(6)

(1) Estimated fair values have been determined by using available market data and valuation methodologies. Judgment is necessarily 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 "Long-Term Debt."

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, 2003, EOG's net accounts receivable balance related to North American natural gas, crude oil and condensate sales included receivables from a major integrated oil and gas company and a major utility company, which constituted 14% and 11%, respectively, of the total balance. The related amounts were collected during early 2004. The amount due from the major utility company at December 31, 2002, which approximated 13% of the North American net accounts receivable balance, was collected during early 2003. No other individual purchaser accounted for 10% or more of the North American net accounts receivable balance at December 31, 2003 and 2002. At December 31, 2003, 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, 2003 and 2002 result from crude oil and natural gas 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. Historical credit losses incurred on receivables by EOG have been immaterial except for those associated with the Enron bankruptcies which were recorded in December 2001.

13. ACCOUNTING FOR CERTAIN LONG-LIVED ASSETS

Periodically, 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 2003, 2002 and 2001, 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 2003, EOG recorded in Impairments pre-tax charges of $21 million and $4 million in the United States and Canada operating segments, respectively. During 2002 and 2001, EOG recorded in Impairments pre-tax charges of $30 million and $39 million, respectively, in the United States 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 $64 million, $38 million and $40 million for 2003, 2002 and 2001, respectively.

14. ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

EOG adopted SFAS No. 143 - "Accounting for Asset Retirement Obligations" on January 1, 2003. The impact of adopting 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 2003 (in thousands):

	Asset Retirement Obligations		
	Short-Term	Long-Term	Total
Balance at December 31, 2002	$ -	$ -	$ -
Carrying Amount at Adoption	6,384	92,097	98,481
Liabilities Incurred	1,364	11,295	12,659
Liabilities Settled	(2,699)	(1,144)	(3,843)
Accretion	140	4,740	4,880
Foreign Currency Translation	131	2,128	2,259
Balance at December 31, 2003	$ 5,320	$ 109,116	$ 114,436

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.

15. INVESTMENT IN CARIBBEAN NITROGEN COMPANY LIMITED AND NITROGEN (2000) UNLIMITED

EOG, through certain wholly-owned subsidiaries, owns equity interests in two Trinidadian companies: CNCL and N2000. During the first quarter of 2003, 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 sale left EOG with equity interests of approximately 12% in CNCL and 27% in N2000 and did not result in any gain or loss.

The other shareholders in CNCL are subsidiaries of Ferrostaal AG, Duke Energy, Halliburton, Koch Industries, Inc. and CL Financial Ltd. At December 31, 2003, investment in CNCL was approximately $14 million. CNCL commenced production in June 2002, and at December 31, 2003, was producing approximately 1,950 metric tons of ammonia daily. At December 31, 2003, CNCL had a long-term debt balance of approximately $218 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 2003, EOG recognized equity income of $3.7 million.

The other shareholders in N2000 are subsidiaries of Ferrostaal AG, Halliburton, Koch Industries, Inc. and CL Financial Ltd. At December 31, 2003, investment in N2000 was approximately $20 million. N2000 is constructing an ammonia plant in Trinidad, at an expected cost of approximately $320 million, and is expected to commence production in the third quarter 2004. At December 31, 2003, N2000 had a long-term debt balance of approximately $172 million, which is non-recourse to N2000's shareholders. EOG will be liable for its share of any pre-completion deficiency funds loans to fund plant cost overruns up to $15 million, approximately $4 million of which is net to EOG's interest. EOG will also be liable for its share of any post-completion deficiency funds loans to fund the costs of operation, payment of principal and interest to the principal creditor and other cash deficiencies of N2000 up to $30 million, approximately $8 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 N2000 and therefore, it accounts for the investment using the equity method.

16. 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 has 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.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS

(In Thousands, Except Per Share Amounts, Unless Otherwise Indicated)
(Unaudited Except for Results of Operations for Oil and Gas Producing Activities)

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, 2003, 2002 and 2001 were based on studies performed by the engineering staff of EOG for reserves in the United States, Canada, Trinidad and the United Kingdom. Opinions by DeGolyer and MacNaughton (D&M), independent petroleum consultants, for the years ended December 31, 2003, 2002 and 2001 covered producing areas containing 72%, 73% and 71%, 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, 2003 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, 2003, 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

Net Proved Reserves	United States	Canada	Trinidad	United Kingdom	TOTAL
Natural Gas (Bcf)					
Net proved reserves at December 31, 2000	1,821.4	545.7	1,013.5	-	3,380.6
Revisions of previous estimates	15.0	(26.8)	(121.6)	-	(133.4)
Purchases in place	66.1	111.5	-	-	177.6
Extensions, discoveries and other additions	358.3	59.7	295.2	-	713.2
Sales in place	(1.0)	-	-	-	(1.0)
Production	(252.5)	(46.0)	(42.0)	-	(340.5)
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**
Liquids (MBbl)					
Net proved reserves at December 31, 2000	52,013	5,817	15,572	-	73,402
Revisions of previous estimates	(3,111)	1,294	(3,691)	-	(5,508)
Purchases in place	586	35	-	-	621
Extensions, discoveries and other additions	12,380	361	1,967	-	14,708
Sales in place	(192)	(35)	-	-	(227)
Production	(9,293)	(820)	(749)	-	(10,862)
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**

	United States	Canada	Trinidad	United Kingdom	TOTAL
Bcf Equivalent (Bcfe)					
Net proved reserves at December 31, 2000	2,133.5	580.6	1,106.9	-	3,821.0
Revisions of previous estimates	(3.7)	(19.1)	(143.7)	-	(166.5)
Purchases in place	69.7	111.6	-	-	181.3
Extensions, discoveries and other additions	432.5	62.0	307.0	-	801.5
Sales in place	(2.2)	(0.2)	-	-	(2.4)
Production	(308.2)	(50.9)	(46.5)	-	(405.6)
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**

Net Proved Developed Reserves at:	United States	Canada	Trinidad	TOTAL
Natural Gas (Bcf)				
December 31, 2000	1,498.6	479.4	207.0	2,185.0
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**
Liquids (MBbl)				
December 31, 2000	42,132	5,695	2,967	50,794
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**
Bcf Equivalents (Bcfe)				
December 31, 2000	1,751.4	513.6	224.8	2,489.8
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**

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, 2003 and 2002:

	2003	2002
Proved Properties(1)	$ 7,990,675	$ 6,527,716
Unproved Properties	198,387	222,379
Total	8,189,062	6,750,095
Accumulated Depreciation, Depletion and Amortization	(3,940,145)	(3,428,547)
Net Capitalized Costs	$ 4,248,917	$ 3,321,548

(1) The 2003 proved properties amount includes asset retirement obligations of $85 million as a result of the adoption of SFAS No. 143 - "Accounting for Asset Retirement Obligations" on January 1, 2003.

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."

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
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 Gross Up	-	14,938	-	-	-	14,938
Total(2)	$ 594,315	$ 201,997	$ 37,346	$ -	$ 2,384	$ 836,042
2001						
Acquisition Costs of Properties						
Unproved	$ 69,308	$ 6,967	$ -	$ -	$ -	$ 76,275
Proved	95,646	72,660	-	-	-	168,306
Subtotal	164,954	79,627	-	-	-	244,581
Exploration Costs	163,602	16,708	13,695	-	8,739	202,744
Development Costs	512,175	92,374	60,969	-	-	665,518
Subtotal	840,731	188,709	74,664	-	8,739	1,112,843
Deferred Income Tax Gross Up	19,411	30,845	-	-	-	50,256
Total(2)	$ 860,142	$ 219,554	$ 74,664	$ -	$ 8,739	$ 1,163,099

(1) Asset Retirement Costs do not include the cumulative effect of adoption. The Asset Retirement Costs for the United States are netted with gains recognized upon settlement of asset retirement obligations of $1 million.

(2) Pro forma total expenditures for 2002 and 2001 are not presented as 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.

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
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
2001						
Natural Gas, Crude Oil and Condensate Revenues	$ 1,295,945	$ 191,096	$ 69,141	$ -	$ 21	$ 1,556,203
Other, Net	1,652	117	-	-	-	1,769
Total	1,297,597	191,213	69,141	-	21	1,557,972
Exploration Expenses	57,602	6,101	3,577	-	187	67,467
Dry Hole Expenses	55,817	6,495	2,828	-	6,220	71,360
Production Costs	219,518	34,426	10,308	35	-	264,287
Impairments	76,801	2,355	-	-	-	79,156
Depreciation, Depletion and Amortization	348,397	31,821	12,031	-	9	392,258
Income (Loss) Before Income Taxes	539,462	110,015	40,397	(35)	(6,395)	683,444
Income Tax Provision (Benefit)	198,243	32,663	22,218	-	(2,238)	250,886
Results of Operations	$ 341,219	$ 77,352	$ 18,179	$ (35)	$ (4,157)	$ 432,558

(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, 2003.

(2) Other includes other international operations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the engineering staff of EOG. 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 and 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
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
2001					
Future cash inflows	$ 5,677,824	$ 1,490,552	$ 1,472,197	$ -	$ 8,640,573
Future production costs	(1,528,474)	(371,124)	(335,395)	-	(2,234,993)
Future development costs	(387,048)	(31,232)	(110,331)	-	(528,611)
Future net cash flows before income taxes	3,762,302	1,088,196	1,026,471	-	5,876,969
Future income taxes	(930,505)	(295,739)	(265,709)	-	(1,491,953)
Future net cash flows	2,831,797	792,457	760,762	-	4,385,016
Discount to present value at 10% annual rate	(1,121,771)	(321,980)	(413,876)	-	(1,857,627)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,710,026	$ 470,477	$ 346,886	$ -	$ 2,527,389

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, 2003:

	United States	Canada	Trinidad	United Kingdom	TOTAL
December 31, 2000	$ 6,011,133	$ 1,513,751	$ 388,553	$ -	$ 7,913,437
Sales and transfers of oil and gas produced, net of production costs	(1,060,926)	(156,787)	(58,832)	-	(1,276,545)
Net changes in prices and production costs	(6,400,910)	(1,822,229)	(194,995)	-	(8,418,134)
Extensions, discoveries, additions and improved recovery net of related costs	347,088	48,271	114,871	-	510,230
Development costs incurred	101,900	27,500	71,088	-	200,488
Revisions of estimated development cost	(5,296)	2,931	10,947	-	8,582
Revisions of previous quantity estimates	(3,563)	(12,536)	47,418	-	31,319
Accretion of discount	862,118	223,154	54,297	-	1,139,569
Net change in income taxes	2,313,068	592,322	15,087	-	2,920,477
Purchases of reserves in place	35,686	78,790	-	-	114,476
Sales of reserves in place	(6,165)	(303)	-	-	(6,468)
Changes in timing and other	(484,107)	(24,387)	(101,548)	-	(610,042)
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**

UNAUDITED QUARTERLY FINANCIAL INFORMATION

	Quarter Ended			
	Mar 31	Jun 30	Sep 30	Dec 31
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
2002				
Net Operating Revenues	$ 186,563	$ 290,163	$ 279,879	$ 338,077
Operating Income (Loss)	$ (20,646)	$ 69,300	$ 61,710	$ 70,613
Income (Loss) Before Income Taxes	$ (35,860)	$ 55,555	$ 42,866	$ 57,111
Income Tax Provision (Benefit)	(11,619)	17,447	13,979	12,692
Net Income (Loss)	(24,241)	38,108	28,887	44,419
Preferred Stock Dividends	2,758	2,758	2,758	2,758
Net Income (Loss) Available to Common	$ (26,999)	$ 35,350	$ 26,129	$ 41,661
Net Income (Loss) per Share Available to Common				
Basic[1]	$ (0.23)	$ 0.31	$ 0.23	$ 0.36
Diluted[1]	$ (0.23)	$ 0.30	$ 0.22	$ 0.36
Average Number of Common Shares				
Basic	115,485	115,737	115,621	114,742
Diluted	115,485	117,689	117,078	116,908

(1) The sum of quarterly net income (loss) 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.

SELECTED FINANCIAL DATA

(In Thousands, Except Per Share Amounts)	Year Ended December 31, 2003	2002	2001
Statement of Income Data:			
Net Operating Revenues	$ 1,744,675	$ 1,094,682	$ 1,655,722
Operating Expenses			
Lease and Well	212,601	179,429	175,446
Exploration Costs	76,358	60,228	67,467
Dry Hole Costs	41,156	46,749	71,360
Impairments	89,133	68,430	79,156
Depreciation, Depletion and Amortization	441,843	398,036	392,399
General and Administrative	100,403	88,952	79,963
Taxes Other Than Income	85,867	71,881	95,333
Charges Associated with Enron Bankruptcy	-	-	19,211
Total	1,047,361	913,705	980,335
Operating Income	697,314	180,977	675,387
Other Income (Expense), Net	15,273	(1,651)	1,168
Interest Expense (Net of Interest Capitalized)	58,711	59,654	45,110
Income Before Income Taxes	653,876	119,672	631,445
Income Tax Provision (Benefit)	216,600	32,499	232,829
Net Income Before Cumulative Effect of Change in Accounting Principle	437,276	87,173	398,616
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(7,131)	-	-
Net Income	430,145	87,173	398,616
Preferred Stock Dividends	11,032	11,032	10,994
Net Income Available to Common	$ 419,113	$ 76,141	$ 387,622
Net Income Per Share Available to Common			
Basic			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 3.72	$ 0.66	$ 3.35
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-
Net Income Per Share Available to Common	$ 3.66	$ 0.66	$ 3.35
Diluted			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 3.66	$ 0.65	$ 3.30
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-
Net Income Per Share Available to Common	$ 3.60	$ 0.65	$ 3.30
Average Number of Common Shares			
Basic	114,597	115,335	115,765
Diluted	116,519	117,245	117,488

(In Thousands)	At December 31, 2003	2002	2001
Balance Sheet Data:			
Net Oil and Gas Properties	$ 4,248,917	$ 3,321,548	$ 3,055,910
Total Assets	4,749,015	3,813,568	3,414,044
Long-Term Debt	1,108,872	1,145,132	855,969
Shareholders' Equity	2,223,381	1,672,395	1,642,686

QUARTERLY STOCK DATA 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 cash dividends declared per share:

	Price Range		Cash
	High	Low	Dividend
2003			
First Quarter	$ 42.83	$ 35.70	$ 0.04
Second Quarter	45.56	36.56	0.04
Third Quarter	42.87	37.70	0.05
Fourth Quarter	47.52	40.85	0.05
2002			
First Quarter	$ 41.32	$ 30.50	$ 0.04
Second Quarter	44.15	37.11	0.04
Third Quarter	39.68	30.02	0.04
Fourth Quarter	42.00	32.40	0.04

As of March 8, 2004, there were approximately 285 record holders of EOG's common stock, including individual participants in security position listings. There are an estimated 75,000 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.

GLOSSARY OF TERMS

Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Bbld	Barrels per day
CEO	Chief Executive Officer
CNCL	Caribbean Nitrogen Company Limited
$/Bbl	Dollars per barrel
$/Mcf	Dollars per thousand cubic feet
$/MMBtu	Dollars per million British thermal units
LNG	Liquefied Natural Gas
MBbl	Thousand barrels
MBbld	Thousand barrels per day
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MMBtu	Million British thermal units
MMBtud	Million British thermal units per day
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
MMcfd	Million cubic feet per day
MMcfed	Million cubic feet equivalent per day
N2000	Nitrogen (2000) Unlimited
NYMEX	New York Mercantile Exchange

DIRECTORS AND OFFICERS

DIRECTORS

George A. Alcorn[1]
Houston, Texas
President, Alcorn Exploration, Inc.

Charles R. Crisp[2]
Houston, Texas
Investments

Mark G. Papa
Chairman and CEO
EOG Resources, Inc.

Edward Randall, III[3]
Houston, Texas
Investments

Edmund P. Segner, III
President and Chief of Staff
EOG Resources, Inc.

Donald F. Textor[4]
Locust Valley, New York
Former Partner/Managing Director
Goldman Sachs

Frank G. Wisner[5]
New York, New York
Vice Chairman
American International Group, Inc.
and former Ambassador to India,
the Philippines, Egypt and Zambia

EXECUTIVE COMMITTEE

Mark G. Papa
Chairman and CEO

Edmund P. Segner, III
President and Chief of Staff

Loren M. Leiker
Executive Vice President,
Exploration and Development

Gary L. Thomas
Executive Vice President, Operations

Barry Hunsaker, Jr.
Senior Vice President and General
Counsel

Sandeep Bhakhri
Vice President and Chief Information
Officer

OFFICERS
(including key subsidiaries)

Lewis Chandler, Jr.
Senior Vice President, Law

Lawrence E. Fenwick
Senior Vice President and General
Manager, EOG Resources Canada Inc.

William R. Thomas
Senior Vice President and General
Manager, Midland

William E. Albrecht
Vice President, Acquisitions and
Engineering

Maire A. Baldwin
Vice President, Investor Relations

Ben B. Boyd
Vice President, Finance and Accounting,
EOG Resources International, Inc.

James R. Breimayer
Vice President and General Manager,
Tyler

Steven B. Coleman
Vice President and General Manager,
Oklahoma City

Gerald R. Colley
Vice President and General Manager,
International
President, EOG Resources
International, Inc.

Phil C. DeLozier
Vice President, Business Development

Kurt D. Doerr
Vice President and General Manager,
Denver

Timothy K. Driggers
Vice President and Chief Accounting
Officer

Patricia L. Edwards
Vice President, Human Resources,
Administration and Corporate Secretary

Robert K. Garrison
Vice President and General Manager,
Corpus Christi

Kevin S. Hanzel
Vice President, Audit

Andrew N. Hoyle
Vice President, Marketing and
Regulatory Affairs

Lindell L. Looger
Vice President and General Manager,
EOG Resources Trinidad Ltd.

David R. Looney
Vice President, Finance and Treasurer

Richard A. Ott
Vice President, Tax

Earl J. Ritchie, Jr.
Vice President and General Manager,
Offshore

Gary L. Smith
Vice President and General Manager,
Pittsburgh

Ronnie L. Adams
Controller, Land Administration

Ann D. Janssen
Controller, Financial Reporting and
Planning

Joseph C. Landry
Controller, Operations Accounting

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

(2) Member, Audit, Compensation, Corporate Governance and Nominating Committees

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

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

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

SHAREHOLDER INFORMATION

Corporate Headquarters
333 Clay Street, Suite 4200
Houston, Texas 77002
P.O. Box 4362
Houston, Texas 77210-4362
(713) 651-7000
Toll Free: (877) 363-EOGR
www.eogresources.com

Common Stock Exchange Listing
New York Stock Exchange
Ticker Symbol: EOG
Common Stock Outstanding at
December 31, 2003: 115,910,400

Principal Transfer Agent
EquiServe Trust Company, N.A.
P.O. Box 2500
Jersey City, New Jersey 07303-2500
Toll Free: (800) 519-3111
Outside U.S.: (201) 324-1225
www.equiserve.com
Hearing Impaired: TDD (201) 222-4955

Annual Meeting of Shareholders

The Annual Meeting of Shareholders will be held at 2 p.m. CDT in the La Salle "A" Room of the Doubletree Hotel, 400 Dallas Street, Houston, Texas 77002 on Tuesday, May 4, 2004. Information with respect to this meeting is contained in the Proxy Statement sent with this Annual Report to holders of record of EOG Resources, Inc. Common Stock. The Annual Report is not to be considered a part of the proxy soliciting material.

Additional Information

Additional copies of the Annual Report and the Form 10-K are available upon request by calling (877) 363-EOGR or through the EOG Resources website at www.eogresources.com. Quarterly earnings press release information and SEC filings also can be accessed through the website.

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

OUR EMPLOYEES Latiff Abdool Gene Abernathy Ismael Abila Erlinda Abrego Rosie Abrego Maria Acevedo Linda Acosta Tammy Adair Ronnie Adams Michael Adrion Candelario Aguilar Amit Ahuja Melissa Albert William Albrecht Patricia Aleman Joseph Alexander Raymond Allbee Kenneth Allen Cathy Anderson David Anderson William Anderson Joseph Anderson Jim Anschutz Barbara Anselm Robert Apperson Andres Arambula Kerry Archibald Blaine Ardelian Rene Argueta Erick Armentrout Ralph Armentrout Donald Armstrong Robert Armstrong Derek Arnold Paul Arnott Terry Avery Balliram Bachan Lanny Baker Twila Baker Maire Baldwin Jerry Ball John Ball Hilary Ballenger Jimmy Banks Valeria Banks Bijay Banthia Brian Baptiste Judy Barlow James Barnes Kelley Barnett Emilio Barrera Anthony Barrett Curt Bateman Carolyn Baughman Dale Bawol Ana Beasley Michelle Beauchamp Jennifer Beavers Gary Beck Carla Beck John Becker Stephen Bedell Barbara Belcher Kenneth Bell Heather Bell Olynda Bello Adriana Benavides Steven Bennett Stephen Benoit Roy Benteau A. John Bergquist Martha Bernardini Kerry Bernas Timothy Berry Berwin Best Sandeep Bhakhri Jerry Biggs Blaine Bischoff Sidney Bjorlie John Black Jennifer Blackburn Randolph Blackburn Brad Blackwood Carolyn Bladek Dana Blevins Stanley Blundell Kenneth Boedeker Susan Boedeker Mark Boehm David Boerm Timothy Boggess Wendy Bone Kelly Bonogofski Alisa Booth Vera Boren Richard Bosch Stewart Bosch James Bouillion Deidra Bourland David Bowdle Jamie Bowman Danny Bowthorpe Ben Boyd John Boyd Mary Bradford Diane Bradley Tom Bradley Sharleen Brand Bryan Brandon Cheryl Brashear James Breimayer Sheila Bremer Judith Bretz Isabelle Briand Mike Brietzke Susan Bright Ann Brindle Gary Britt Rachel Britt Sonia Brittain Joan Broadley Kim Brooks Michael Brooks Burt Broussard Crystal Brown Elizabeth Brown Jeff Brown William Brown Jody Brown Steve Brown Robert Brown David Brunette Linda Bruster Alecia Bryson Steven Bryson James Bucci Shauna Buhr Kerry Burdett Geoff Burkart Rick Burke Wesley Burke John Burnette Tina Burns Laurie Burt Paul Burt Craig Burton Timothy Butkus Debbie Butler Kenneth Byrd William Byrd Kim Cadena Brad Cage Robert Cahill Gary Cain Mark Cain Delma Callier Howard Cameron Carol Cameron Melany Cammaert Carleen Campbell Catherine Campbell Daniel Canales David Canales Charlotte Candler Joseph Caputo John Cardin Santos Cardona Charleen Carlos Kathleen Carlson Skipper Carnes Ronald Carney Stacy Carpenter Jacqueline Carr-Brown Noemi Carrillo Leland Carroll Ricky Carroll Robert Carroll Kenneth Carter Gary Cartwright Susan Carulli Nanci Cassard Jesus Castillo Randall Cate Dennis Cates Paula Chaffin Rinu Chahal Katherine Chalfant Shelly Chan Robert Chancey Lewis Chandler John Chapman William Chapman Andres Chavez Linda Chenoweth Clara Chiew Helen Chin Michael Chong Tracey Chong-Ashing Lorne Christal Beverly Christensen Samie Clanton John Clark Julie Clay Tamara Clayton Toni Clifton-Wood Eugene Clower Linda Cluiss April Colbert Ruby Cole Carolyn Coleman James Coleman Steven Coleman Robert Coles Gerald Colley Charles Colson Christian Combs Traci Conner Paul Connolly Barry Constable Duane Cook Karen Cook Michael Cooksey Tyler Coon Lisa Copeland Craig Cormany Neal Cormier Roy Coston Stephen Couch David Covill Betty Cowart Emily Cowen Kim Cowherd Dawn Marie Cox Mark Cox Jack Cozart Hal Crabb Logan Craig Alicia Craigwell Douglas Cramer Garth Cramer Bette Cranford John Cranmore Nora Crawford Sherry Crawford Wayland Crawley Misti Creach Robert Crim Paul Cross Barry Crowder Phyllis Croy Stephen Croy Herminia Cruz Wade Cuch Gerald Culpepper Valerie Culpepper Ferdinand Cumberbatch James Cunkelman Peter Cunningham Pamela Currey Louis D'Abadie Diana Dabiedeen Jeff Dahl Lee Dailey Donald Daisher Fassil Daniel Robert Daniels Leandro Daponte Judy Dargin Roger Dart Bryan David Donald Davis Randall Davis Robert Davis Warren Davis Richard Day David Deal Teresa Dean Alma Dehoyos Howard Deis Elizabeth DeLaGarza Chris Delcambre Gloria DelCampo James DelCampo Joseph DelCampo Brenda Dellinger Phil Delozier Betty Der-Griffiths Marie Deslattes Ronald Devoll Curtis Dill Trudy Dillon-Patrick John Dixon Kurt Doerr Daniel Domingue Manuel Dominguez Kathryn Donaldson Daryl Doodnath Timothy Dort Patrick Draves Timothy Driggers Denis Dufresne Cynthia Duge James Dunford Lane Dunham Kenneth Dunn George Dupre Brian Durman Frederick Ealand Louise Earl Karen Ebbert Madeline Edgley Patricia Edwards Ronald Einerson Cynthia Einkauf Jerome Ellard Terrence Elliot Edward Elliott Robert Ellis John Ellyson William Elmer Jerome Elmlinger Ronald Ensminger Darrah Eresman Karen Erwin Marc Eschenburg Sandra Estrada Betty Evans Carol Evans-Danver Beverly Fabian Clyde Faggett Roger Falk Richard Fansher Carol Faullon Melanie Fehr Lawrence Fenwick William Fergeson Len Ferguson Richard Ferguson Olga Ferrell Perry Fields Marilyn Fish Douglas Fiske James Fletcher Criselda Flores Daniel Flores Clifford Fobes Richard Fobes James Folcik Grace Ford Lindsay Ford Larry Formo Therese Foster Larry Fournier John Fowler Lonnie Fox Charles Francis Janie Franco Lydia Franco Christine Frank Danny Frederick Joe Freeman Reginald Freestone Judy Frey Bonita Friesenhahn David Frye Laura Fuentes Barbara Ganong Stephen Garber Agustin Garcia Maria Garcia Vic Garcia Michael Gardner Dwayne Garnett Robert Garrison Richard Gauthier Debra Gay Marshall Gazette Maria Geerligs Zola George James Gerlinger John Gibson Owen Gibson Murray Gilhooly Clinton Gilles Victor Gilliam Melissa Gillispie David Gilmore Michael Goad Frank Gomez Rosa Gonzalez Jeffrey Gordon Casey Gordy Mark Gorski Vickie Graham Patricia Granger Bonnie Grant Doris Grau Dortha Gray Katherine Gray Eldon Greanya Janice Green Jayne Green Ruth Green Norma Greenlee James Gregory Julie Grey Wendi Grieve Dana Griffin Larry Gross Nicholas Groves Joseph Guerrero John Guillot Michelle Gummelt Emelia Guzman Laura Guzman Lula Hain Kent Hale Leta Hale Morris Hall Vivi Ann Hall Robert Halverson Patricia Hambright Phillip Hampton Debbra Hamre Susan Hanselman Christian Hansen Andrew Hanson Kevin Hanzel Ricky Hardaway Robert Harp Dorothy Harris Jamie Harris Joe Harris Kristina Harris Burton Hartley Lance Hartwell Tracy Hartzog Mark Hately James Hatfield Tammy Hatfield Michele Hatz Gina Hauck Darcy Hawkins Gordon Haycraft Indira Heeralal Michael Heil Walter Heinlen Lloyd Helms Jennifer Henderson Ronald Henderson Bryan Hendricks Bryan Hennigan Carla Henry Dan Henry David Henry James Henry Eduardo Hernandez Irene Herrera Stephen Hertig Paul Herzing Thomas Heydt Tom Heydt Deborah Hibler Vicki Hietpas John Hill Elise Hillman Stephen Himes Linda Hoagland James Hodgson Chris Hoefer Deanna Hoffman Myron Hoffman Sheryl Holmes Helen Hosein-Mulloon Glenn Howard Stephen Howell William Howells Adriana Howells Andrew Hoyle Donna Hradil Frank Hudec John Hudec Brandy Hudson Carolyn Hughes Deanne Hulquist Wan-Hsiang Hung Barry Hunsaker Jacklin Hunt Michael Huntington Raymond Ingle Greg Ingram Kathleen Insley Michael Isaacs Elizabeth Ivers Diana Jablonski Herschel Jackson Kenneth Jackson Melinda Jackson Ronnie Jackson Camille Jacobs George James Ann Janssen Darryl Janssen Donna Jenkins Willie Jenkins Donna Jensen M. Teresa Jimenez Craig Jobe Joyce John Bruce Johnson Deborah Johnson Donna Johnson Joyce Johnson Nancy Johnson Richard Johnson Sonya Johnson John Johnston Patricia Johnston Vickie Jolley Calvert Jones Dennis Jones Gregg Jones Matthew Jones Sherry Jones Douglas Jordan Jon Jorgenson James Joyce Julie Judkins Sheri Jurecek Teresa Kaplan Terrence Karka Srinivasulu Karnati Steven Keenan Thomas Keetley Brenda Keith Theodore Kelly Howard Kemp Tammy Kennedy Wilbur Kennedy Sara Kerley Mphatso Khoza Robert Kidney Richard King Rick King Colin Kinniburgh Carol Kirksey Timothy Kirksey Tracy Kisell Denise Klatt Mildred Kleinschmidt Ronald Knippa David Kocian Anthony Koester Saul Korrodi Joseph Kozeal Nancy Krahn Lynn Krailo Mark Kraus Lisa Krawchuk Ronald Krieger Anthony Krupa Darcy Kubik Albert Kucharski Shrut Kumar Charles Kunze Sharon Kurzy Cyril Lackey Ernest LaFlure Renee Lagrone Andrew Lai Gordon Lain Cori Lambert George Lambert Joseph Landry John Lang Richard Lanning Janice Laughery Bill Laughlin Joan Laury Peggy Lavine Felicia Lawal Jill Lawhon Renee Lawrence Herman Lawson Lugard Layne Kim-Hue Le Michael LeBaron DonnaMarie Lee William Leflar Tommy Lehman Loren Leiker Philip Leimer Roy Lemasters Charles Lemon Kevin Leonce Brent Lesy Herman Leung Randolph Lewellen Clara Lewis Neil Lewis Marianne Lewis Allen Light James Ligon Helen Lim Warren Lindland Stephen Lipari Scott Listiak Elaine Lloyd Milford Lockwood Curtis Lodhar David Long Richard Long Robert Long Mark Longden Lindell Looger David Looney Annel Lopez Juan Lopez Jerome Lopez Robert Love Gloria Loveless Allen Luckow Jeanene Lueckemeyer Clarissia Lynn Pamela MacDonald Mary Maestas Darryl Magnusson Charles Mallary Marla Mallett-Davis Preston Mansor Donald Manton Tony Maranto Kenneth Marbach Colleen Marples Jacob Marshall Heather Marshall Debra Martin Patricia Martin Thelma Martin Antonio Martinez Cathy Mathias Mark Mathias Beverly Matthews Mervin Matus David May Jeffrey May Vicki McAteer Robert McAuley Naomi McBeath Ronald McBee George McBride Marilyn McCall Christopher McCarthy Ricky McCaslin Kenn McComb Thomas McCray Karen McDaniel John McDonald Beverly McMahan Roger McMannis Tolliver McNeill Megan McWhorter Linda Meade David Meadows John Mears Joseph Meeks John Melby David Men David Metzner Gail Meyer Tina Meyer Eloise Meza Kenneth Middlemiss Rudy Mikulec Matthew Miller Toni Miller Robert (Joe) Milne Sheila Mirich Amy Mitchell Karen Mitchell Chris Moffat Terence Mok Lisa Molinar Steven Molitor Anthony Monariti Steven Montez Delores Montoya Judith Montoya Aramis Morales Jackie Morgan Ronald Morgan Douglas Morgareidge Andrew Morris William Morris Kristin Morton Richard Morton Michael Moton Pat Moya Douglas Mueller Michael Mullins Edward Mumford Linda Munoz Robert Munoz Daniel Murton Ramey Musgrave Christopher Myers Harrienarine Nanan Shareen Nash Heather Nealson Todd Neely Brian Neemar Jimmy Nelson Shona Ness Adrian Neumann Brenda Neumann Charles Newberry John Nicholas Judy Nichols Mark Nicholson Thomas Nielsen Richard Nies Orrison Niles Xiaomei Ning Sherly Nissing Virginia Nobs Benjamin Nolan Joel Noronha Lori Nugent Timothy Nugent Janie Null Terry Nunn Martha Nutter Alison Oblinger Kolton Obritsch Dermot O'Connor Lori Odom John O'Donnell Julie Ogren Karen O'How Brittney O'Kelley Michelle Oliver Daniel Olson David O'Neill Carmen Oney Jay Orr D. Alexander Orr Richard Ott Jacky Ouin Ray Owsley Andrew Pakes Debra Palmer John Palmer David Palmer Mike Palmquist Mark Papa Tracy Pape Kevin Parker Theodore Parrish Curtis Parsons Michael Partin William Pauly Brenda Payne Debrah Payne Brent Pears Annette Pearsall Richard Pedder J.D. Marc Pellow Paul Pendleton Katherine Perez Kim Perez Stacy Perez Tricia Perkins David Perkinson Sandra Perko Vanessa Pete Joseph Peter Donald Peters James Peterson Russell Petry Timothy Petta James Pettibone Kenneth Pfau Kevin Pfister Dorothy Pflughaupt Alec Pham Georgia Phillips Sammy Pickering Silvestre Pineda Karen Pitman Donald Pitts Darcy Poncsak Kyla Porche Chad Pottruff Earnest Powell Virginia Powers Donald Presenkowski Debbie Price John Price Susan Price Ralph Proksell Raymond Prudnick James Pusley Michael Quinn Shawn Racca Marjorie Rael Elizabeth Ramirez Rodolfo Ramirez Ann Ramlochan Gregory Ramsey Keith Rasmussen Rance Rasmussen Stanley Rauh Jimmy Redfearn Gilberda Reed Cheryl Reese Anna Reeves Kathleen Reeves Derek Reiber Kelly Reiber Terry Rekdal Elaine Reykdal Fred Rhodes Ronald Richard Clarence Ries Jerry Rietveld Cris Riley Jeffrey Risinger Earl Ritchie Roy Roach Wilbur Roane Marvin Roark Clifford Roberts Rita Robicheaux Bettie Robinson Carl Robinson Lynita Robinson Samuel Robinson Kaye Rockel Elitha Rocke-Maharaj Jeanne Rodgers Debra Rodieck David Rolando Linda Romano Cindi Rosenau Sarah Rotermann Patricia Roufs Bridget Row Kelly Roy Kenneth Roy Stephen Ruiz Douglas Runkel Jeanette Rutherford Amy Rybacki Paul Sacco David Saldivar Ellen Saldivar Ivan Salick Gina Salinas Linda Samford Inocente Sanchez Bobby Sanders Danny Sandifer Marikay Saranthus Edgar Sarmiento Roderick Sauter James Schaefer Rick Schatz Wendi Scheier Darla Schmaltz Jerry Schmaltz Brian Schmidt Shane Schneider Gerald Schneider Shaun Schnurer Keith Schnurer Curtis Schoenfeld Margaret Schroeder Helen Schroller Leann Schroller Paul Schuler Bobby Schultz Frederick Schultz Alfreda Schulz Charles Schwab Michael Schween Kim Schwoerke Dolores Scotka Andrew Scott Marion Sczykutowicz Urban Seay Edmund Segner Brian Sehn Mel Sehn Markie Senn Hector Serna Larry Seymour Gregory Shaffer Pamela Shaffer Eneta Sharma Douglass Sharp John Sheehan Donald Shelden Ted Shell Sidney Shepperd Tracy Shipp Dale Short Michael Sickon Jacqueline Sides Daryl Siebens Teena Simmons Cynthia Simon Ria Singh-Date Sallie Singleton Trent Skelton Robert Slavens Gary Slusher Joseph Smathers Linda Smedlund Ace Smith Charles Smith Delmer Smith Gary Smith Kevin Smith Robert Smith Shawn Smith Sheila Smith Thomas Smith Cheryle Snow Janie Snyder Katherine Sohns Larry Solomon Billie Sowle Deborah Sparks Dallas Spear Debra Spears Anslem Spears William Speer Jeff Spencer Nicholas Spencer John Spradley Stephanie Spriggins Robert Springman Terrie Springman Alan Stacy Manuel Staffero Jack Staley Randall Stanger Bridgett Staples Patti Steely Walter Stefanik Verna Stein Jason Steinkey Brenda Stephens Robert Sterling Martha Sterner Carrie Stevens Phillip Stevens Rodney Steward Kent Stewart Kenneth Stillman Jerry Stinson Rex Stout Scott Stovin Wade Stovin Hugh Stowe Cindy Stowell Jeffrey Strausser Elton Street John Studt Jason Sugg Suvarna Sule Abigail Superville Gary Superville David Swauger Richard Swimm Sundai Swinney James Szenasy Valarie Taber Dara Tatum Edward Taylor Heidi Taylor Jeane Taylor Kenneth Taylor James Terando Martin Thering Eileen Thoede Gary Thomas Kimberly Thomas Melva Thomas Rita Thomas William Thomas J. Layton Thomas Robert Thompson Mark Thorne Dewayne Tidwell Joseph Tigner Gina Tobey Brent Tocher Kelly Tompkins Ola Tompkins Brian Tompkins Celerino Torres Patrick Tower Dominico Tran Linda Tran Tuongvan Tran Steven Travis Marcus Trevino David Trice Jonell Trodlier Delbert Trolinder John Troschinetz Joseph Troupe Bella Trudel Linda Tucker Valerie Tuitt Cameron Turnbull Linda Turner Lawrence Tuttle Zane Tymrick Jeffrey Uecker Tull Umphres Sherry Upton Andrea Urciuoli Vance Utri David Vague Brian Valencia Michael VanHorn Cynthia VanRanken Michael Vargo Martha Varice Terry Vaughn Evelyn Vauthier Jennifer Vega Emiliano Vela Mark Verhoeve George Vieira Cheryl Vierling Larry Vinson Timothy Vogler Andrew Volk Prody Vong Bruce Vosshall George Vouronikas Dallas Wagner Frederic Wagner Dennis Wagstaff Roger Wainwright Deborah Wakeford Matthew Walden Paula Waldo Amanda Walker Wanda Walls Joseph Walthall Deborah Walther Cynthia Walton Charles Wampler Martin Wang Allan Wanner Laura Wardlaw William Wardlaw Freddie Warren Andrew Washburn Alan Watkins Melvin Watson Steven Weatherl Robert Weeks Kenneth Weiland Tyson Weinberger Amanda Weishuhn Michael Welch William Weldon Katherine Wells Ronald Wells Donald Wendland Steven Wentworth Jeffrey Wenz Kari Wenz Gary West Robert West Erica Westphalen James Whaley Kathleen Wharton William Wheaton Michael White Stephen White Jeffrey Whitehair Alison Whiteley Melanie Whitlock Donald Whitmer John Wilkins Nancy Wilkins Cheryl Williams Raymond Williams Steven Williams Alicia Wilson Daniel Wilson Danny Wilson James Wilson Leila Wilson Robert Wilson Walter Wilson Frank Wilson Jesse Winget Sharron Winter Lucia Wong J. Woods David Work Lloyd Woychuk David Wright David Wright Angela Wysocki Theresa Wysocki Craig Young Angie Young Qian Yu Angela Yule Jeffrey Zawila Craig Zempel Barry Zinz eog resources

333 Clay Street, Suite 4200
Houston, Texas 77002

P.O. Box 4362
Houston, Texas 77210–4362
(713) 651-7000
www.eogresources.com