noble energy

2003 ANNUAL REPORT

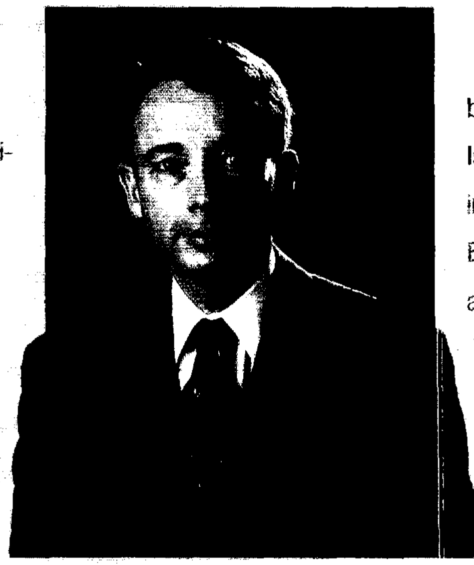
T R A N S I T I O N

ABOUT THE COVER

Noble Energy has made large, multi-year international capital investments over the past several years and, as a result, the company is in a position to deliver substantial growth. Noble Energy is now in a transition to become a different company, one with strong growth and the financial flexibility to pursue a variety of strategic options.

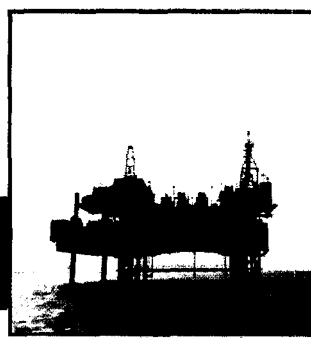
LETTER TO SHAREHOLDERS

During 2003, Noble Energy reached several milestones in positioning itself as a major international competitor among the independent exploration and production companies. During the year we achieved first production in China, began initial production from the Phase 2A expansion project in Equatorial Guinea, and began commissioning our facilities in Israel at the close of the year. These international projects have Noble Energy well positioned for dramatic and sustainable growth for the future. With their completion, we are seeing our international capital commitments declining rapidly and being replaced by increased cash flow from international operations.



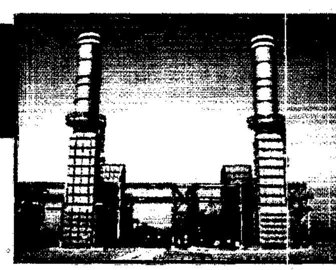
Charles D. Davidson - Chairman of the Board, President and Chief Executive Officer

Noble Energy had a strong year in 2003, both financially and operationally. The company reached several milestones for its international projects and had an active and successful domestic program.



In South Bohai Bay offshore China, production commenced from the Cheng Dao Xi (CDX) field in January 2003.

MachalaPower had its first full year of operations in 2003. The Machala power plant is the only natural gas-fired commercial power plant in Ecuador and is one of the lowest cost producers of thermal power in the country.

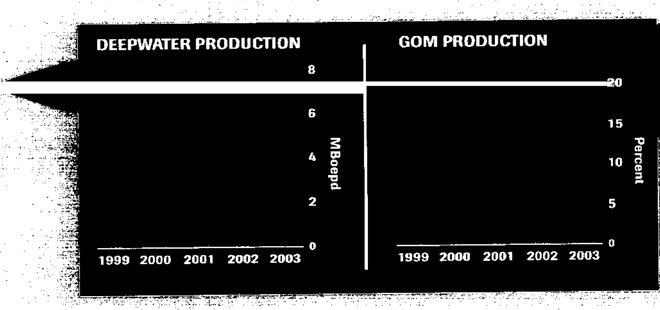


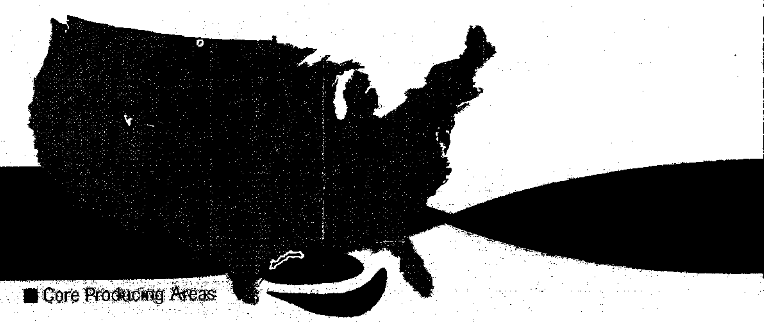
Our domestic business was active in 2003 as well. An active onshore drilling program led to several discoveries and new production. Most of our onshore drilling was focused along the Gulf Coast, where we have built a substantial prospect inventory. Offshore, in the deepwater region of the Gulf of Mexico, we announced a discovery at the Lorien prospect and start of production from the Boris field. Our deepwater production has now grown to a level that represents 20 percent of our total Gulf of Mexico production. In the shelf region of the Gulf of Mexico, we saw new production from the Roaring Fork field beginning in the third quarter.

During 2003, we also identified and prepared for sale five packages of domestic non-core properties. This divestiture program is intended to reduce costs and streamline our business. At the close of the year, sales were completed on four of the property packages.

In January of 2003 we started up the CDX field located in the Bohai Bay of China. This represented the company's first production from China. Noble Energy is the operator of the field and owns a 57 percent interest. Current production from the field, net to Noble Energy's interest, is nearly 3,800 barrels of oil per day (Bopd).

Production from deepwater has become a significant component of Noble Energy's Gulf of Mexico operations and has grown rapidly over the past several years.





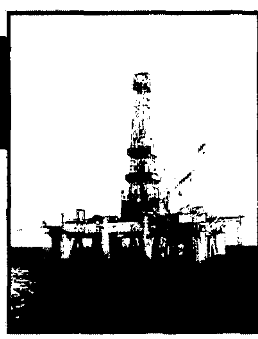
Noble Energy had an active onshore drilling program in 2003. Drilling was focused along the Gulf Coast where the company maintains a substantial prospect inventory.

In 2002, Noble Energy and the other owners of the Alba field in Equatorial Guinea committed to a major expansion of the field's production capacity. This expansion project, which is comprised of two phases, came about as a result of several years of successful delineation drilling that significantly increased estimates of recoverable resources. The Phase 2A expansion began operation in November of 2003 and is expected to ramp up to its full incremental rate by the end of the first quarter of 2004. Phase 2A is expected to add approximately 8,400 barrels per day (Bpd) of new condensate production, net to Noble Energy's interest, when full capacity is reached. Phase 2B is expected to start operation at the end of 2004 with incremental liquefied petroleum gas (LPG) and condensate production of approximately 5,700 Bpd, net to Noble Energy's interest.

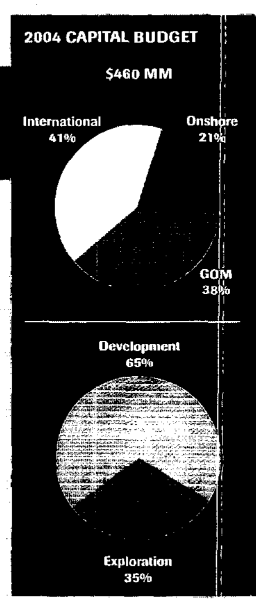
In late December of 2003, we received approval from the government of Israel to begin commissioning our facilities that will allow us to begin natural gas sales from the giant Mari-B field in 2004. With the completion of this major project, we expect net natural gas sales in Israel to increase to approximately 40 million cubic feet per day (MMcfpd) by the end of the first quarter in 2004 and to twice that amount by

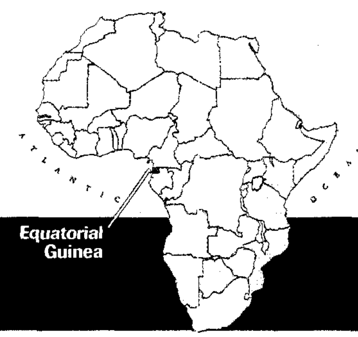
2004 marks the first year following a significant transformation for Noble Energy. International capital commitments are declining rapidly, while major international projects are beginning to contribute earnings and cash flow.

Noble Energy's natural gas project in Israel was completed in 2003, and sales began in early 2004.



With international commitments declining, Noble Energy's 2004 capital budget was reduced to $460 million from capital expenditures of $544 million in 2003. The 2004 budget includes worldwide drilling and the completion of Phase 2B in Equatorial Guinea.





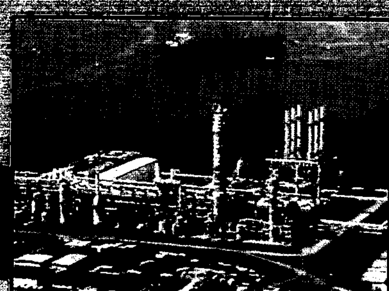
In Equatorial Guinea, the company's Phase 2A condensate expansion project was completed and commenced operations in 2003. Gross incremental production from Phase 2A is expected to reach 27,700 Bpd by the end of the first quarter of 2004.

the end of the year. This project is expected to be a source of strong earnings and cash flow to the company for many years into the future.

2003 was a year of strong financial performance as well. Our full year earnings of $78 million significantly exceeded the $18 million of earnings reported for 2002. Net cash provided by operating activities in 2003 was $603 million. The increase in earnings and cash flow resulted primarily from higher production volumes and higher realized commodity prices. The strong commodity price environment we realized in 2003 has continued into 2004. Our growth in cash flow, coupled with property sales and capital discipline, also helped strengthen our balance sheet; year-end total debt was $934 million, a reduction of $92 million from the previous year.

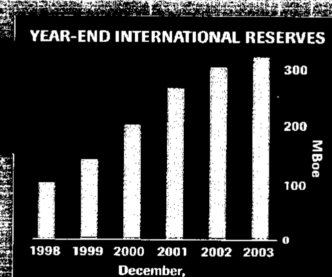
As we begin 2004 we remain excited about the potential of our company. We find ourselves uniquely positioned to deliver production growth for several years, and we expect to continue to benefit from the substantial investments we have made in international projects. Our active drilling programs are focused in the areas that we believe have the best potential for delivering superior value and are backed by an out-

With major international commitments nearly complete, Noble Energy is well positioned to generate growth for several years.



The Phase 2B condensate and production project in Equatorial Guinea will be complete at the end of 2004. After the ramp up of Phase 2B, gross liquids production from the Alba field will be nearly 70,000 Bpd.

Since 1998, international reserves have grown at an annual rate of 28 percent.

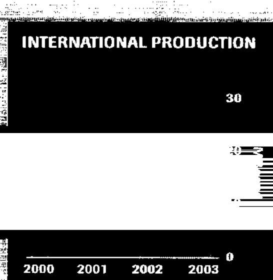


standing staff of employees. Our marketing group continues to enhance the value of our production while providing important services to their customers.

Noble Energy sets high standards for itself for reporting and governance. We continue to enhance these standards and processes, which we believe are important for maintaining investor confidence in our company. Our website now includes an area dedicated to governance. Our entire company remains committed to carrying out our operations throughout the world with the utmost care for the environment and the safety of our employees and neighbors.

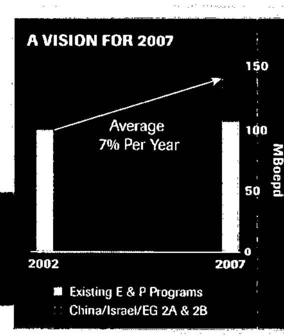
We offer our thanks to James C. Day who will not be standing for reelection to our board this year. Jim has been a strong supporter of the company and we wish him well. We also acknowledge our other directors and employees for their commitment and dedication to Noble Energy, and thank our shareholders for their continued support.

Charles D. Davidson
Chairman of the Board, President
and Chief Executive Officer



Since 2000, international production has grown at an annual rate of 42 percent.

The Mari-B and Noa fields in Israel are estimated to contain over one trillion cubic feet (Tcf) of natural gas resources and represent a substantial growth opportunity for the company.



Noble Energy's major international projects are now nearly complete. These projects provide the foundation for seven percent expected average annual production growth through 2007.

DOMESTIC OPERATIONS

Domestic operations, including discontinued operations, reported 2003 operating income of $86.7 million compared to operating income of $35.2 million in 2002 (see Geographical Data and Discontinued Operations footnote disclosures of the 2003 Noble Energy, Inc. Form 10-K). Excluding the effect of non-cash charges totaling $100.1 million, operating income was $186.8 million. The non-cash charges include: 1) write down to market value and net realized loss of $59.2 million, 2) impairment of operating assets of $31.9 million and 3) cumulative effect of SFAS 143 of $9.0 million. Full year 2003 results, including discontinued operations, benefited from year-on-year increases in crude oil and natural gas prices of 15 percent and 50 percent, respectively.

HIGH-GRADED ASSETS

Noble Energy maintains a high quality asset portfolio with additions from exploration success and selective acquisitions, coupled with the sale of mature non-core properties. During 2003, Noble Energy sold four packages of non-core properties.

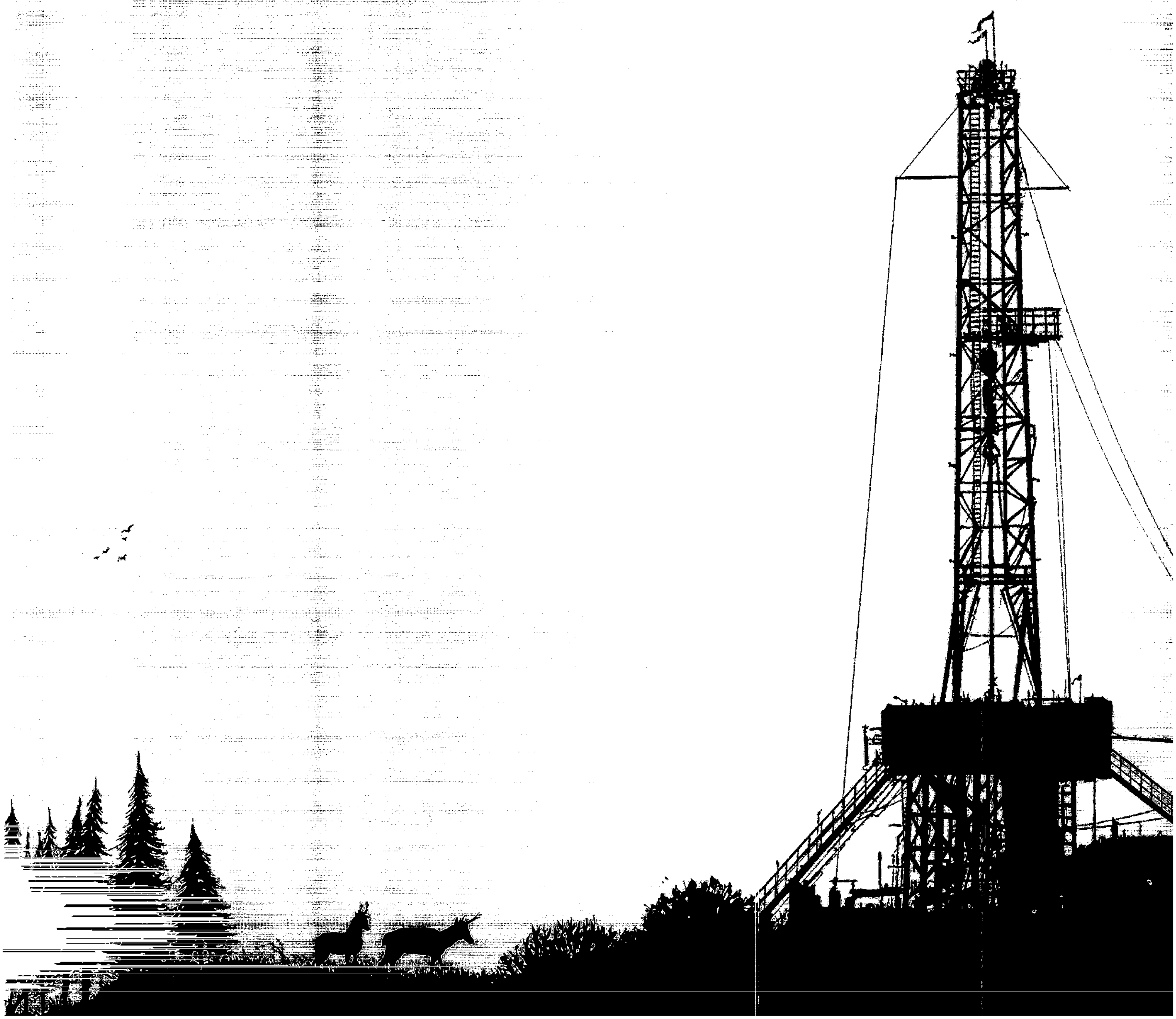
During 2003, Noble Energy identified five packages of non-core domestic properties to be sold. The properties held for disposition were reported as discontinued operations. Overall, these properties represented approximately six percent of year-end reserves and nine percent of 2003 production.

For 2004, Noble Energy has budgeted capital expenditures of $270 million for domestic operations, with approximately two-thirds earmarked for the offshore division and one-third for the onshore division. The offshore division's spending plan calls for a split between exploration and development of 44 percent and 56 percent, respectively. For the onshore division, exploration expenditures are expected to total 61 percent of the division's budget.

Domestic Onshore Noble Energy's domestic onshore division is focused in the Gulf Coast areas of Texas and Louisiana. The company also has a presence in Colorado, Kansas, Montana, Nevada, Oklahoma, Wyoming and California. The company owns an interest in over 537,000 net acres onshore.

Onshore capital expenditures totaled $94 million in 2003. Noble Energy's onshore drilling program included 80 gross (59 net) exploration and development wells. Of the wells drilled in 2003, 50 (63 percent) were commercial discoveries.

The Gulf Coast region remains one of Noble Energy's most active areas. During 2003, the company drilled 45 wells in the Gulf Coast with a 53 percent success rate. A substantial portion of Noble Energy's drilling activity was in the Aspect Area of Mutual Interest, with 26 wells drilled and 13 successes. Also in the Gulf Coast, Noble Energy had a three-well program on its Wildcat Ridge project. Two of the three wells drilled were successful, and additional prospects will be drilled in 2004. The company has a 37.5 percent working interest in the Wildcat Ridge project.



HIGH-GRADED ASSETS

In south Louisiana, Noble Energy drilled and completed a discovery well and successful offset in Lafourche Parish. The wells were producing 2,400 barrels of oil equivalent per day (Boepd), gross, at year-end 2003. Noble Energy owns a 40 percent working interest in the prospect.

In Duval County, Texas, Noble Energy drilled six wells, of which five were successful. The prospects were identified with proprietary 3-D seismic acquired in late 2002. The five successful wells were producing 2,160 Boepd, gross, at year-end 2003. Noble Energy's working interests in the wells drilled in 2003 range from 85 percent to 100 percent.

Domestic Offshore Noble Energy's domestic offshore division produces and explores for crude oil and natural gas in the Gulf of Mexico's conventional shelf, deep shelf (geologic objectives below 15,000 feet) and deepwater. The company owns an interest in over 850,000 net acres in 342 blocks, 80 of which are in the deepwater.

FOCUSED EXPLORATION

Noble Energy has revamped its exploration processes to manage risk and increase returns. Its domestic exploration activities are concentrated in three areas: the Gulf Coast onshore, the deepwater Gulf of Mexico, and the deep shelf of the Gulf of Mexico.

By focusing its exploration efforts in high-potential regions where the company has accumulated substantial experience, Noble Energy is well positioned to achieve superior results.

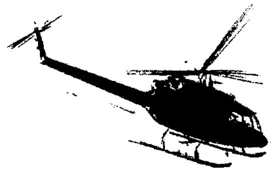
Offshore capital expenditures totaled $123 million in 2003. Noble Energy's offshore drilling program included 20 gross (six net) exploration and development wells. Of the wells drilled in 2003, 14 (70 percent) were commercial discoveries.

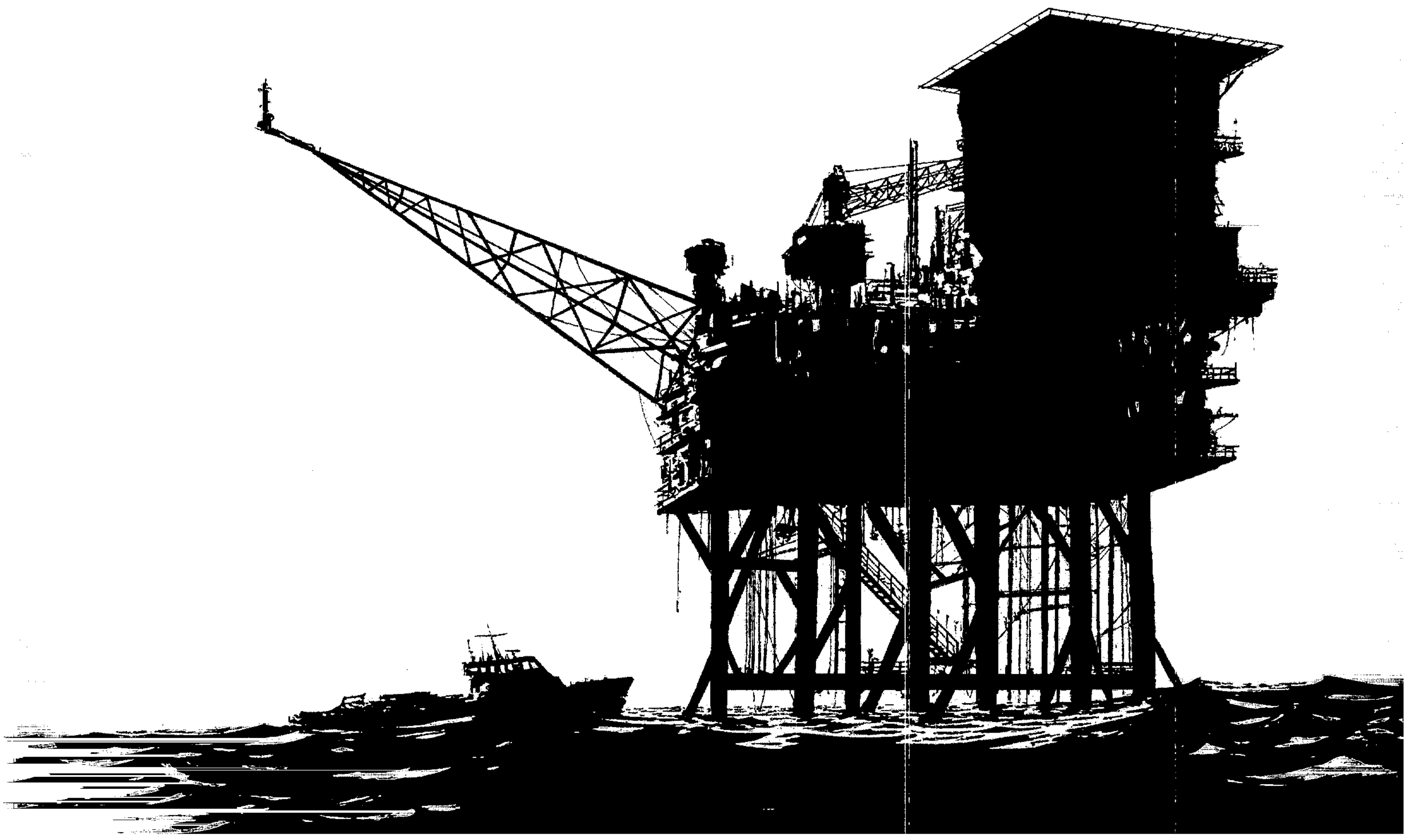
Over the past two years, as a result of increasing finding and development costs and declining prospect sizes in the Gulf of Mexico's traditional shallow shelf, Noble Energy has increasingly shifted the focus of its domestic offshore exploration program to the Gulf of Mexico deep shelf and deepwater. Relative to the conventional shallow Gulf of Mexico, both are under-explored, have the potential for significant discoveries and offer improved returns.

Noble Energy has drilled 27 exploration wells in the deep shelf over the past three years, of which 15 have been discoveries, for a success rate of 56 percent.

During 2003, Noble Energy's deepwater program included the development of three previous discoveries and one new discovery:

1. Green Canyon 199 (Lorien) – 20 percent working interest to Noble Energy, discovery announced in July 2003. Located in 2,177 feet of water and drilled to a total depth of 17,482 feet, the well encountered over 120 feet of apparent oil in a high-quality reservoir interval. Further appraisal will be conducted in 2004;
2. Green Canyon 136 A-8 (Shasta) - 25 percent working interest to Noble Energy, commenced production in January 2003 at 30 MMcfpd gross;
3. Green Canyon 282 (Boris) – 25 percent working interest to Noble Energy, commenced produc-





FOCUSED EXPLORATION

tion from the first well in February 2003 at 15,000 Boepd gross. The second well commenced production during the third quarter 2003. Combined, Boris #1 and #2 produced at a rate of 25,500 Boepd gross;

4. Mississippi Canyon 837 (Loon) – 40 percent working interest to Noble Energy, expected to commence production during the first quarter 2004 at 12 MMcfpd gross.

INTERNATIONAL OPERATIONS

International operations reported 2003 operating income of $113.4 million compared to operating income of $59.8 million in 2002. Full year 2003 results reflected several important factors:

- A year-on-year increase in realized prices for liquids and natural gas;
- Strong realized methanol prices in Equatorial Guinea;
- A full year of operations from the Machala power plant in Ecuador;
- The start-up of crude oil production in China in January 2003; and
- The start-up of the Phase 2A condensate expansion project in Equatorial Guinea in late November 2003.

Year-end 2003 international reserves totaled 322 million barrels of oil equivalent (MMBoe), of which 56 percent were natural gas.

In 2003, international production averaged 32,605 Boepd compared to 25,956 Boepd in 2002. The increase in production volumes was primarily attributable to the start-up of crude oil production in China in January 2003 and a full year of production in Ecuador.

For 2004, Noble Energy has budgeted capital expenditures of $189 million for international operations, of which 84 percent is dedicated to production and development projects. Planned expenditures include $95 million in the Mid-east and Africa, $74 million in the Far East and Latin America, and $20 million in the North Sea. The 2004 international capital budget is $132 million lower than 2003 expenditures, reflecting the completion and start-up of Noble Energy's natural gas project in Israel and the Phase 2A expansion in Equatorial Guinea.

Of the expenditures in the Mid-east and Africa, over 90 percent are for the construction of facilities for the Phase 2B project in Equatorial Guinea to increase production of condensate and LPG. Nearly three-quarters of the expenditures budgeted for the Far East and Latin America are for development drilling on the Amistad field offshore Ecuador.

EXPANDING PRODUCTION

With several major international projects just completed or nearing completion, Noble Energy is positioned to experience a significant increase in production over the next several years.

- Ecuador – Commenced natural gas and power production in September 2002;
- China - Commenced crude oil production in January 2003;
- Israel – Commenced natural gas sales in February 2004;
- Equatorial Guinea - Commenced expanded condensate production in November 2003. Additional condensate and LPG production increases scheduled through early 2005.

EXPANDING PRODUCTION

Equatorial Guinea Noble Energy's largest field (Alba) is located offshore Equatorial Guinea. As of year-end 2003, Equatorial Guinea had total net proved reserves of 203 MMBoe. Average production in Equatorial Guinea, net to Noble Energy, was 13,028 Boepd, or 13 percent of the company's total production.

Total operating income in Equatorial Guinea, which includes results from field operations and methanol, increased 119 percent to $86.1 million in 2003 compared to $39.3 million last year. The substantial increase in operating income in 2003 primarily reflected higher volumes and prices for condensate and methanol.

Condensate production increased 21 percent in 2003, compared to 2002, due to improved production efficiencies. Natural gas and methanol sales volumes increased 16 percent in 2003 as the methanol plant operated with less maintenance related downtime than the prior year.

MONETIZING STRANDED NATURAL GAS

Noble Energy has recently completed three significant international projects that will lead to the monetization of stranded natural gas assets.

- Ecuador - Constructed an onshore power plant designed to utilize natural gas resource from the Amistad field offshore
- Israel - Discovered over one Tcf of natural gas that facilitated the establishment of a significant new gas market in the country
- *Equatorial Guinea - The company and its partners constructed one of* the world's lowest cost methanol plants to convert stranded natural gas to methanol.

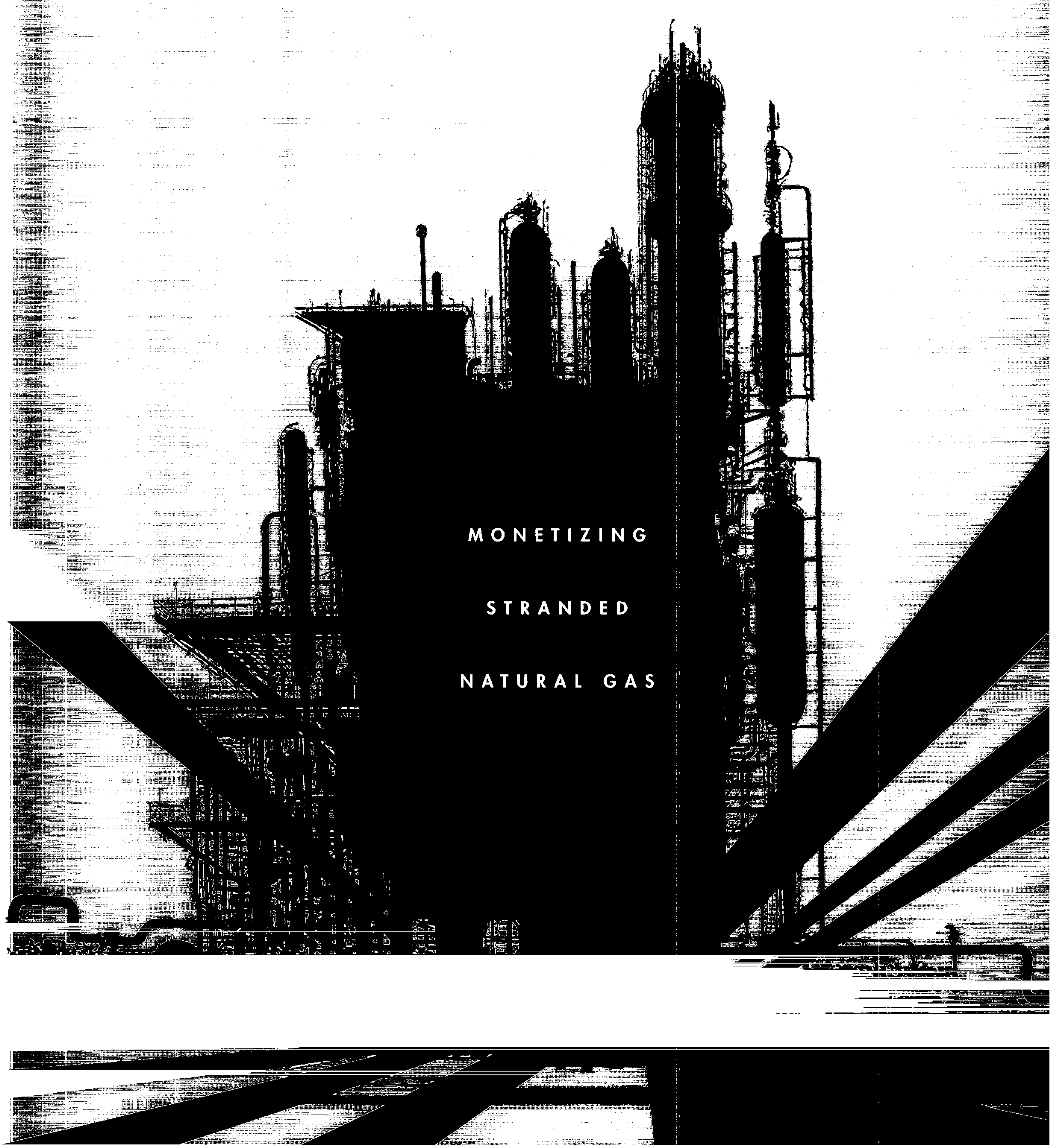
Higher realized condensate and methanol prices also contributed to the increased earnings. The average realized price for condensate during 2003 was $27.93 per barrel (Bbl) compared to $23.88 for the prior year. The average realized price for methanol during 2003 was 65 cents per gallon (GAL) compared to 43 cents last year.

LPG, natural gas and condensate sales accounted for $45.5 million, or 53 percent, of operating income from Equatorial Guinea. The other 47 percent of operating income was produced by Atlantic Methanol Production Company (AMPCO) methanol operations.

AMPCO, an unconsolidated subsidiary in which the company owns a 45 percent interest, markets methanol in Europe and the United States. In 2003, AMPCO produced $40.6 million of operating income net to Noble Energy's interest, more than four times last year's operating income. AMPCO results are reported as income from unconsolidated subsidiaries. The company's share of AMPCO methanol sales volumes was 122.0 million gallons (MMGal), compared to 105.1 MMGal in 2002.

A large expansion project designed to increase liquids production at the Alba field is currently underway. The project is divided into two phases, Phase 2A and Phase 2B.

In late November, Noble Energy reached an important milestone in its international expansion with the start up of Phase 2A, which is designed to increase gross condensate production by approximately 27,700 Bpd. Completion of Phase 2A positions the company for a substantial increase in condensate volumes beginning in 2004. Construction on Phase 2B, which promises to generate additional significant


MONETIZING
STRANDED
NATURAL GAS

volume increases beginning in 2005, is currently underway. Phase 2B is expected to increase gross condensate and LPG production by approximately 6,000 Bpd and 14,000 Bpd, respectively.

North Sea In the North Sea, 2003 operating income was $42.4 million, compared to $37.4 million the prior year. The year-on-year improvement reflects higher crude oil and natural gas prices, which increased 19 percent and 23 percent, respectively. Higher commodity prices were partially offset by higher exploration expenses.

North Sea production for 2003 was 9,722 Boepd, compared to 10,679 Boepd in 2002, reflecting the sale of the company's 1.34 percent interest in the Claymore field and natural field decline.

During the year, Noble Energy participated in one non-operated discovery in the North Sea. This discovery is expected to lead to future development.

Other International Other international, which includes operating results from Argentina, China, Ecuador, Israel and Vietnam, recorded a 2003 operating loss of $15.0 million, compared to an operating loss of $16.9 million in 2002. The smaller operating loss resulted from the start-up of crude oil production in China in January 2003 and a full year of electricity production in Ecuador, partially offset by higher exploration expense in Israel and Vietnam.

Other international exploration expense totaled $41.7 million for 2003 compared to $23.5 million last year. Of the total exploration expense recorded for 2003, $20.2 million is attributable to the company's decision to write off its investment in Vietnam. The non-cash write-off of the company's investment in Vietnam was offset by a $14.3 million cash tax benefit.

TRANSITIONING TO A CASH GENERATOR

Noble Energy has made large, multi-year international capital investments over the past several years and, as a result, is in a position to deliver substantial growth. Noble Energy is now in a transition to become a dramatically different company, one with strong growth, stable operations and the financial flexibility to pursue a variety of strategic options. The company will deliver value to its shareholders through production growth, a stronger balance sheet, reduced operating costs and improved margins.

China In January 2003, Noble Energy commenced crude oil production from the CDX field, located in South Bohai Bay off the coast of China. Noble Energy's project in China contributed $2.5 million of operating income during 2003. For the year, the company produced 3,295 Bopd at an average realized price of $27.22 per Bbl. Noble Energy is operator of the CDX field with a 57 percent working interest.

Ecuador The start-up of the Machala power plant in September 2002 was another major milestone in Noble Energy's international expansion. The Machala power plant contributed $7.2 million of operating income during 2003. For the year, 751,689 megawatts (MW) were produced at an average sales price of 7.7 cents per kilowatt hour (Kwh).

TRANSITIONING TO A CASH GENERATOR

The Machala power plant is a simple cycle generator with capacity of 130 MW from twin turbines. It is the only natural gas-fired commercial power generator in Ecuador and one of the lowest cost producers of thermal power in the country. Noble Energy, through its subsidiaries EDC Ecuador Ltd. and MachalaPower Cia. Ltda., has a 100 percent ownership interest in the fully integrated gas-to-power project. The project includes the Amistad natural gas field, which supplies fuel to the Machala power plant.

To date, Noble Energy has completed three development wells in the Amistad field that can supply approximately 30 MMcfpd of natural gas to the power plant. Additional development drilling is planned for 2004.

Israel One of the company's largest and most important international projects was commissioned in Israel in late December 2003. Natural gas production from the Mari-B field in the Mediterranean Sea offshore Israel will increase throughout 2004 as the Israel Electric Corporation (IEC) develops its capacity to take natural gas at its Ashdod electric power plant. Noble Energy and its partners have contracted to sell an average of 170 MMcfpd of natural gas to IEC over an 11-year period beginning in January 2004. Natural gas sales commenced in February 2004.

Beyond its current contract with IEC, Israel represents substantial growth potential for Noble Energy. The company has entered into a non-binding term sheet with one industrial user and is exploring other opportunities to provide additional natural gas from Mari-B to IEC and other parties. Israel has a number of potential industrial natural gas consumers, and average annual electricity demand is expected to grow over the next several years. With the Mari-B production facilities designed to produce up to 600 MMcfpd, the company is positioned to expand production at minimal additional cost.

Noble Energy has participated in two significant offshore natural gas discoveries in Israel. The Noa field discovery was made in 1999, and the Mari-B field discovery occurred in 2000. As of year-end 2003, Noble Energy has booked net reserves from Mari-B of 450 billion cubic feet. Noble Energy is the operator of the Israel project with a 47 percent working interest.

OUTLOOK

Noble Energy has made significant progress over the past several years and is now poised to deliver substantial growth over the coming years. The company has made large, multi-year international capital investments that were funded by domestic operations and through increased borrowing. Those capital commitments are declining rapidly, while the international projects are only just beginning to contribute. As a result, Noble Energy is now becoming a dramatically different company, one uniquely positioned to deliver value to its shareholders through production growth, a stronger balance sheet and improved margins.

Form 10-K

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

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware *(State of incorporation)*	73-0785597 *(I.R.S. employer identification number)*
100 Glenborough Drive, Suite 100 Houston, Texas *(Address of principal executive offices)*	77067 *(Zip Code)*

(Registrant's telephone number, including area code)
(281) 872-3100

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $3.33-1/3 par value	New York Stock Exchange, Inc.
Preferred Stock Purchase Rights	New York Stock Exchange, Inc.

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes__X__ No______

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.___X_

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes__X__ No______

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2003: $2,085,000,000.
Number of shares of Common Stock outstanding as of March 1, 2004: 57,710,547.

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2004 Annual Meeting of Stockholders to be held on April 27, 2004, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2003, are incorporated by reference into Part III.

TABLE OF CONTENTS

PART I.

PART II.

PART III.

PART IV.

PART I

Item 1. Business.

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk--Cautionary Statement for Purposes of the Private Securities Litigation Reform Act of 1995 and Other Federal Securities Laws" of this Form 10-K.

General

Noble Energy, Inc. (the "Company" or "Noble Energy"), formerly known as Noble Affiliates, Inc., is a Delaware corporation that has been publicly traded on the New York Stock Exchange since 1980. Noble Energy has been engaged, directly or through its subsidiaries, in the exploration, production and marketing of crude oil and natural gas since 1932, when Noble Energy's predecessor, Samedan Oil Corporation ("Samedan"), was organized. Noble Energy was organized in 1969 under the name "Noble Affiliates, Inc." and was Samedan's parent entity until Samedan was merged into Noble Energy at year-end 2002. The Company is noted for its innovative methods of marketing its international gas reserves through projects such as its methanol plant in Equatorial Guinea and its gas-to-power project in Ecuador.

In this report, unless otherwise indicated or the context otherwise requires, the "Company" or the "Registrant" refers to Noble Energy, Inc. and its subsidiaries. Effective December 31, 2001, Energy Development Corporation ("EDC") was merged into Samedan. Effective December 31, 2002, Noble Trading, Inc. ("NTI") was merged into Noble Gas Marketing, Inc. ("NGM") under the name of Noble Energy Marketing, Inc. ("NEMI").

As of January 1, 2003, the Company's wholly-owned subsidiary, NEMI, markets the majority of the Company's domestic natural gas as well as third-party natural gas. NEMI also markets a portion of the Company's domestic crude oil as well as third-party crude oil. For more information regarding NEMI's operations, see "Item 1. Business--Crude Oil and Natural Gas--Marketing" of this Form 10-K.

In this report, the following abbreviations are used:

Bbl	Barrel	Mcf	Thousand cubic feet
Bbls	Barrels	Mcfpd	Thousand cubic feet per day
MBbls	Thousand barrels	Mcfe	Thousand cubic feet equivalent
Bpd	Barrels per day	MMcf	Million cubic feet
Bopd	Barrels oil per day	MMcfepd	Million cubic feet equivalent per day
MMBbl	Million barrels	MMcfpd	Million cubic feet per day
MBpd	Thousand barrels per day	Bcf	Billion cubic feet
MMBpd	Million barrels per day	Bcfe	Billion cubic feet equivalent
MBopd	Thousand barrels oil per day	Bcfepd	Billion cubic feet equivalent per day
MMBopd	Million barrels oil per day	Bcfpd	Billion cubic feet per day
BOE	Barrels oil equivalent	BTU	British thermal unit
MMBoe	Million barrels oil equivalent	BTUpcf	British thermal unit per cubic foot
MMBoepd	Million barrels oil equivalent per day	MMBTU	Million British thermal unit
$MM	Millions of dollars	MMBTUpd	Million British thermal unit per day
Kwh	Kilowatt hour	MTpd	Metric tons per day
MW	Megawatt	LPG	Liquefied petroleum gas
MWH	Megawatt hours		

For reporting BOE or Mcfe, one Bbl of oil, condensate or LPG is equal to six Mcf of natural gas.

Crude Oil and Natural Gas

Noble Energy, directly or through its subsidiaries or various arrangements with other companies, explores for, develops and produces crude oil and natural gas. Exploration activities include geophysical and geological evaluation and exploratory drilling on properties for which the Company has exploration rights. The Company has exploration, exploitation and production operations domestically and internationally. The domestic areas consist of: offshore in the Gulf of Mexico and California; the Gulf Coast Region (Louisiana and Texas); the Mid-Continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, Nevada, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel), the North Sea (Denmark, the Netherlands and the United Kingdom) and Vietnam. For more information regarding Noble Energy's crude oil and natural gas properties, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Exploration, Exploitation and Development Activities

Domestic Offshore. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in the Gulf of Mexico (Texas, Louisiana, Mississippi and Alabama) and California since 1968. The Company has shifted its domestic offshore exploration focus to the Gulf of Mexico deep shelf and deepwater areas, and away from the Gulf of Mexico's conventional shallow shelf, in order to take advantage of larger prospect sizes and potential higher rates of return. The Company's current offshore production is derived from 186 gross wells operated by Noble Energy and 299 gross wells operated by others. At December 31, 2003, the Company held offshore federal leases covering 932,820 gross developed acres and 755,658 gross undeveloped acres on which the Company currently intends to conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Domestic Onshore. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in three regions since the 1930s. The Gulf Coast Region covers onshore Louisiana and Texas. The Mid-Continent Region covers Oklahoma and Kansas. Properties in the Rocky Mountain Region are located in Colorado, Montana, Nevada, Wyoming and California.

Noble Energy's current onshore production is derived from 1,330 gross wells operated by the Company and 511 gross wells operated by others. At December 31, 2003, the Company held 667,708 gross developed acres and 351,201 gross undeveloped acres onshore on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Argentina. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in Argentina since 1996. The Company's producing properties are located in southern Argentina in the El Tordillo field, which is characterized by secondary recovery crude oil production from a 10,000 acre reservoir. At December 31, 2003, the Company held 28,988 gross developed acres and 2,426,221 gross undeveloped acres in Argentina on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

China. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in China since 1996. The Company has a concession offshore China in the southern portion of Bohai Bay. At December 31, 2003, the Company held 7,413 gross developed acres and 1,617,549 gross undeveloped acres in China on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Ecuador. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in Ecuador since 1996. The Company is currently utilizing the gas in the Amistad gas field (offshore Ecuador), which was discovered in the 1970s, to generate electricity through its 100 percent-owned natural gas-fired power plant, located near the city of Machala. With a current generating capacity of 130 MW of electricity, additional capital investment for combined cycle to the power plant could ultimately increase capacity to generate 220 MW of electricity into the Ecuadorian power grid. The concession covers 12,355 gross developed acres and 851,771 gross undeveloped acres encompassing the Amistad field. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Equatorial Guinea. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties offshore Equatorial Guinea (West Africa) since 1990. Production is from the Alba field, which produces natural gas and condensate. The majority of the natural gas production is sold to a methanol plant, which began production in the second quarter of 2001. The methanol plant has a contract through 2026 to purchase natural gas from the Alba field. The plant is owned by Atlantic Methanol Production Company LLC ("AMPCO"), in which the Company owns a 45 percent interest through its ownership of Atlantic Methanol Capital Company ("AMCCO"). For more information on the methanol plant, see "Item 1. Business--Unconsolidated Subsidiaries" of this Form 10-K.

At December 31, 2003, the Company held 45,203 gross developed acres and 266,754 gross undeveloped acres offshore Equatorial Guinea on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Israel. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in the Mediterranean Sea, offshore Israel, since 1998. The Company owns a 47 percent interest in three licenses and two leases. At December 31, 2003, the Company held 123,552 gross developed acres and 292,572 gross undeveloped acres located about 20 miles offshore Israel in water depths ranging from 700 feet to 5,000 feet. Noble Energy and its partners announced, on December 24, 2003, the commencement of production of natural gas from its Mari-B field. Sales of natural gas to Israel Electric Corporation ("IEC") began in February 2004 under a definitive agreement executed in June 2002. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

North Sea. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in the North Sea (Denmark, the Netherlands and the United Kingdom) since 1996. At December 31, 2003, the Company held 66,354 gross developed acres and 573,838 gross undeveloped acres on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Vietnam. In December 2003, Noble Energy elected not to pursue any additional exploration efforts in the Nam Con Son Basin of Vietnam. As a result, the Company wrote off its investment in Vietnam and is in the process of assigning its ownership in the two blocks. During 2003, the Company expensed one exploratory well and associated exploration costs.

Production Activities

Revenues from sales of crude oil, natural gas and gathering, marketing and processing ("GMP") have accounted for approximately 90 percent or more of consolidated revenues for each of the last three fiscal years.

Operated Property Statistics. The percentage of properties operated by the Company indicates the amount of control over timing of operations. The percentage of operated crude oil and natural gas wells on both the well count and percentage of sales volume basis are shown in the following table as of December 31:

	2003		2002		2001	
(in percentages)	*Oil*	*Gas*	*Oil*	*Gas*	*Oil*	*Gas*
Operated well count basis	19.6	60.1	23.3	62.8	24.8	60.6
Operated sales volume basis	33.3	48.8	29.3	45.1	37.2	52.3

Non-operated Property Statistics. The percentage of non-operated crude oil and natural gas wells on both the well count and the percentage of sales volume basis are shown in the following table as of December 31:

	2003		2002		2001	
(in percentages)	*Oil*	*Gas*	*Oil*	*Gas*	*Oil*	*Gas*
Non-operated well count basis	80.4	39.9	76.7	37.2	75.2	39.4
Non-operated sales volume basis	66.7	51.2	70.7	54.9	62.8	47.7

Net Production. The following table sets forth Noble Energy's net crude oil and natural gas production, including royalty, from continuing operations, for the three years ended December 31:

	2003	*2002*	*2001*
Crude oil production (MMBbl)	13.1	10.6	9.1
Natural gas production (Bcf)	122.9	124.5	129.8

Crude Oil and Natural Gas Equivalents. The following table sets forth Noble Energy's net production stated in crude oil and natural gas equivalent volumes, including royalty, from continuing operations, for the three years ended December 31:

	2003	*2002*	*2001*
Total crude oil equivalents (MMBoe)	33.6	31.4	30.8
Total natural gas equivalents (Bcfe)	201.7	188.2	184.5

Acquisitions of Oil and Gas Properties, Leases and Concessions

During 2003, Noble Energy spent approximately $1.2 million on the purchase of proved crude oil and natural gas properties. The Company spent approximately $8.0 million in 2002 and $97.6 million in 2001 on the acquisition of proved properties. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

During 2003, Noble Energy spent approximately $10.2 million on acquisitions of unproved properties. The Company spent approximately $30.6 million in 2002 and $81.3 million in 2001 on acquisitions of unproved properties. These properties were acquired primarily through various offshore lease sales, domestic onshore lease acquisitions and international concession negotiations. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Dispositions of Oil and Gas Properties

During 2003, the Company identified five packages of non-core domestic properties to be sold. The properties held for disposition were reported as discontinued operations. Overall, these properties represented approximately six percent of year-end reserves and nine percent of 2003 production. Four of the five packages closed in 2003; the fifth is scheduled to close in the first half of 2004. The Company received $79.9 million from the sale of the four packages. The estimated reserves associated with these four packages were 17.2 MMBoe.

During 2002, the Company sold approximately 4.1 MMBoe of reserves and received approximately $20.4 million from the sale of properties.

Marketing

NEMI seeks opportunities to enhance the value of the Company's domestic natural gas production by marketing directly to end-users and aggregating natural gas to be sold to natural gas marketers and pipelines. During 2003, approximately 86 percent of NEMI's total sales were to end-users. NEMI is also actively involved in the purchase and sale of natural gas from other producers. Such third-party natural gas production may be purchased from non-operators who own working interests in the Company's wells or from other producers' properties in which the Company may not own an interest. NEMI, through its wholly-owned subsidiary, Noble Gas Pipeline, Inc., engages in the installation, purchase and operation of natural gas gathering systems.

Noble Energy has a short-term natural gas sales contract with NEMI, whereby the Company is paid an index price for all natural gas sold to NEMI. The contract does not specify scheduled quantities or delivery points and expires on May 31, 2004. The Company sold approximately 64 percent of its natural gas production to NEMI in 2003. NEMI's revenues from sales of natural gas, including related derivative financial transactions, less cost of goods sold are reported in GMP. All intercompany sales and expenses are eliminated in the Company's consolidated financial statements. The Company has a small number of long-term natural gas contracts representing approximately four percent of its 2003 natural gas sales.

Substantial competition in the natural gas marketplace continued in 2003. The Company's average natural gas price increased $1.24 from $2.89 per Mcf in 2002 to $4.13 per Mcf in 2003. Due to the volatility of natural gas prices, the Company, from time to time, has used derivative instruments and may do so in the future as a means of controlling its exposure to commodity price changes. For additional information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk" and "Item 8. Financial Statements and Supplementary Data" of this Form 10-K.

Crude oil produced by the Company is sold to purchasers in the United States and foreign locations at various prices depending on the location and quality of the crude oil. The Company has no long-term contracts with purchasers of its crude oil production. Crude oil and condensate are distributed through pipelines and by trucks to gatherers, transportation companies and end-users. NEMI markets approximately 34 percent of the Company's crude oil production as well as certain third-party crude oil. The Company records all of NEMI's revenues from sales of crude oil, less cost of goods sold, as GMP. All intercompany sales and expenses are eliminated in the Company's consolidated financial statements.

Crude oil prices are affected by a variety of factors that are beyond the control of the Company. The Company's average crude oil price from continuing operations increased $3.50 from $24.22 per Bbl in 2002 to $27.72 per Bbl in 2003. Due to the volatility of crude oil prices, the Company, from time to time, has used derivative instruments and may do so in the future as a means of controlling its exposure to price changes. For additional information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk" and "Item 8. Financial Statements and Supplementary Data" of this Form 10-K.

The largest single non-affiliated purchaser of the Company's crude oil production in 2003 accounted for approximately 16 percent of the Company's crude oil sales, representing approximately six percent of total revenues. The five largest purchasers accounted for approximately 57 percent of total crude oil sales. The largest single non-affiliated purchaser of the Company's natural gas production in 2003 accounted for approximately five percent of its natural gas sales, representing approximately three percent of total revenues. The five largest purchasers accounted for approximately 18 percent of total natural gas sales. The Company does not believe that its loss of a major crude oil or natural gas purchaser would have a material effect on the Company.

Regulations and Risks

General. Exploration for and production and sale of crude oil and natural gas are extensively regulated at the international, national, state and local levels. Crude oil and natural gas development and production activities are subject to various laws and regulations (and orders of regulatory bodies pursuant thereto) governing a wide variety of matters, including allowable rates of production, prevention of waste and pollution and protection of the environment. Laws affecting the crude oil and natural gas industry are under constant review for amendment or expansion and frequently increase the regulatory burden on companies. Noble Energy's ability to economically produce and sell crude oil and natural gas is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the United States and laws and regulations of foreign nations. Many of these governmental bodies have issued rules and regulations that are often difficult and costly to comply with, and that carry substantial penalties for failure to comply. These laws, regulations and orders may restrict the rate of crude oil and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory burden on the crude oil and natural gas industry increases its costs of doing business and consequently affects the Company's profitability.

Certain Risks. In the Company's exploration operations, losses may occur before any accumulation of crude oil or natural gas is found. If crude oil or natural gas is discovered, no assurance can be given that sufficient reserves will be developed to enable the Company to recover the costs incurred in obtaining the reserves or that reserves will be developed at a sufficient rate to replace reserves currently being produced and sold. The Company's international operations are also subject to certain political, economic and other uncertainties including, among others, risk of war, expropriation, renegotiation or modification of existing contracts, taxation policies, foreign exchange restrictions, international monetary fluctuations and other hazards arising out of foreign governmental sovereignty over areas in which the Company conducts operations.

Environmental Matters. As a developer, owner and operator of crude oil and natural gas properties, the Company is subject to various federal, state, local and foreign country laws and regulations relating to the discharge of materials into, and the protection of, the environment. The unauthorized release or discharge of crude oil or certain other regulated substances from the Company's domestic onshore or offshore facilities could subject the Company to liability under federal laws and regulations, including the Oil Pollution Act of 1990, the Outer Continental Shelf Lands Act and the Federal Water Pollution Control Act, as amended. These laws, among others, impose liability for such a release or discharge for pollution cleanup costs, damage to natural resources and the environment, various forms of direct and indirect economic losses, civil or criminal penalties, and orders or injunctions, including those that can require the suspension or cessation of operations causing or impacting or potentially impacting such release or discharge. The liability under these laws for such a release or discharge, subject to certain specified limitations on liability, may be large. If any pollution was caused by willful misconduct, willful negligence or gross negligence within the privity and knowledge of the Company, or was caused primarily by a violation of federal regulations, the Federal Water Pollution Control Act provides that such limitations on liability do not apply. Certain of the Company's facilities are subject to regulations that require the preparation and implementation of spill prevention control and countermeasure plans relating to the prevention of, and preparation for, the possible discharge of crude oil into navigable waters.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," imposes liability on certain classes of persons that generated hazardous substances that have been released into the environment or that own or operate facilities or vessels onto or into which hazardous substances are disposed. The Resource Conservation and Recovery Act, as amended, ("RCRA") and regulations promulgated thereunder, regulate hazardous waste, including its generation, treatment, storage and disposal. CERCLA currently exempts crude oil, and RCRA currently exempts certain crude oil and natural gas exploration and production drilling materials, such as drilling fluids and produced waters, from the definitions of hazardous substance and hazardous waste, respectively. The Company's operations, however, may involve the use or handling of other materials that may be classified as hazardous substances and hazardous wastes, and therefore, these statutes and regulations promulgated under them would apply to the Company's generation, handling and disposal of these materials. In addition, there can be no assurance that such exemptions will be preserved in future amendments of such acts, if any, or that more stringent laws and regulations protecting the environment will not be adopted.

Certain of the Company's facilities may also be subject to other federal environmental laws and regulations, including the Clean Air Act with respect to emissions of air pollutants.

Certain state or local laws or regulations and common law may impose liabilities in addition to, or restrictions more stringent than, those described herein.

The environmental laws, rules and regulations of foreign countries are generally less stringent than those of the United States, and therefore, the requirements of such jurisdictions do not generally impose an additional compliance burden on the Company or on its subsidiaries.

The Company has made and will continue to make expenditures in its efforts to comply with environmental requirements. The Company does not believe that it has to date expended material amounts in connection with such activities or that compliance with such requirements will have a material adverse effect upon the capital expenditures, earnings or competitive position of the Company. Although such requirements do have a substantial impact upon the energy industry, they do not appear to affect the Company any differently or to any greater or lesser extent than other companies in the industry.

Insurance. The Company has various types of insurance coverages as are customary in the industry that include, in various degrees, directors and officers liability, general liability, well control, pollution, terrorism acts and physical damage insurance. The Company believes the coverages and types of insurance are adequate.

Competition

The oil and gas industry is highly competitive. Many companies and individuals are engaged in exploring for crude oil and natural gas and acquiring crude oil and natural gas properties, resulting in a high degree of competition for desirable exploratory and producing properties. A number of the companies with which the Company competes are larger and have greater financial resources than the Company.

The availability of a ready market for the Company's crude oil and natural gas production depends on numerous factors beyond its control, including the level of consumer demand, the extent of worldwide crude oil and natural gas production, the costs and availability of alternative fuels, the costs and proximity of pipelines and other transportation facilities, regulation by state and federal authorities and the costs of complying with applicable environmental regulations.

Unconsolidated Subsidiaries

Through its ownership in AMCCO, the Company owns a 45 percent interest in AMPCO, which completed construction of a methanol plant in Equatorial Guinea in the second quarter of 2001. During 1999, AMCCO issued $125 million Series A-2 senior secured notes due December 15, 2004 to fund construction payments owed in connection with the construction of the methanol plant. The Company's investment in the methanol plant is included in investment in unconsolidated subsidiaries. The $125 million Series A-2 notes are in current installments of long-term debt on the Company's balance sheet.

The plant construction started during 1998, and initial production of commercial grade methanol commenced May 2, 2001. The plant is designed to produce 2,500 MTpd of methanol, which equates to approximately 20,000 Bpd. At this level of production, the plant would purchase approximately 125 MMcfpd of natural gas from the 34 percent-owned Alba field. The methanol plant has a contract through 2026 to purchase natural gas from the Alba field. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 9 - Unconsolidated Subsidiaries" of this Form 10-K.

Geographical Data

The Company has operations throughout the world and manages its operations by country. Information is grouped into five components that are all primarily in the business of crude oil and natural gas exploration, exploitation and production: United States, North Sea, Israel, Equatorial Guinea, and Other International, Corporate and Marketing. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 11 - Geographical Data" of this Form 10-K.

Employees

The total number of employees of the Company decreased during the year from 624 at December 31, 2002, to 583 at December 31, 2003. In addition, one hundred sixty-seven foreign nationals worked in Noble Energy offices in China, Ecuador, Israel, the United Kingdom and Vietnam as of December 31, 2003.

Available Information

The Company's website address is *www.nobleenergyinc.com*. Available on this website under "Investor Relations - Investor Relations Menu - SEC Filings," free of charge, are Noble Energy's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Forms 3, 4 and 5 filed on behalf of directors and officers and amendments to those reports as soon as reasonably practicable after such materials are electronically filed with or furnished to the United States Securities and Exchange Commission ("SEC").

Also posted on the Company's website, and available in print upon request of any stockholder to the Investor Relations Department, are charters for the Company's Audit Committee, Compensation, Benefits and Stock Option Committee, Corporate Governance and Nominating Committee and the Environmental, Health and Safety Committee. Copies of the Code of Business Conduct and Ethics and the Code of Ethics for Chief Executives and Senior Financial Officers governing our directors, officers and employees (the "Codes") are also posted on the Company's website under the "Corporate Governance" section. Within the time period required by the SEC and the New York Stock Exchange, Inc., the Company will post on its website any modifications to the Codes and any waivers applicable to senior officers as defined in the applicable Code, as required by the Sarbanes-Oxley Act of 2002.

Item 2. Properties.

Offices

The principal corporate office of the Registrant is located in Houston, Texas. The Company maintains offices for international, domestic onshore and domestic offshore operations in Houston, Texas. The Company also maintains offices in China, Ecuador, Israel, the United Kingdom and Vietnam. NEMI's office is located in Houston, Texas. The Company also maintains offices in Ardmore, Oklahoma for centralized accounting, division orders, employee benefits, information systems and related administrative functions.

Crude Oil and Natural Gas

The Company searches for potential crude oil and natural gas properties, seeks to acquire exploration rights in areas of interest and conducts exploratory activities. These activities include geophysical and geological evaluation and exploratory drilling, where appropriate, on properties for which it acquired exploration rights. During 2003, Noble Energy drilled or participated in the drilling of 164 gross (66.6 net) wells, comprised of 64 gross (10.1 net) international wells and 100 gross (56.5 net) domestic wells. For more information regarding Noble Energy's oil and gas properties, see "Item 1. Business--Crude Oil and Natural Gas" of this Form 10-K.

Domestic Offshore. During 2003, Noble Energy's offshore drilling program included 20 gross (6.1 net) exploration and development wells. Of the wells drilled in 2003, 14 wells, or 70 percent, were commercial discoveries and six wells were dry holes.

Green Canyon 136 A-8 (Shasta) commenced production in January 2003 at 30 MMcfpd gross. Noble Energy has a 25 percent working interest in Shasta. The reserves on this previously existing field were recorded in prior years.

Green Canyon 199 (Lorien), an apparent deepwater crude oil discovery in 2003, is located in 2,177 feet of water and was drilled to a total depth of 17,432 feet. The well encountered over 120 feet of oil in a high-quality reservoir interval. Further appraisal will be conducted in 2004. The Company did not record any discovery of reserves on this property in 2003. The Company has a 20 percent working interest in Lorien.

Green Canyon 282 (Boris), a deepwater crude oil discovery, commenced production from the second well in the third quarter of 2003 at an initial gross rate of 4,000 Bopd and 7 MMcfpd. Combined with the discovery well, the field's gross production was 20,000 Bopd and 33 MMcfpd at January 1, 2004. The Company has a 25 percent working interest in Boris. The reserves on this property were recorded in 2001 and 2002 without a flow test but did utilize other testing procedures.

Mississippi Canyon 837 (Loon), a deepwater natural gas discovery in 2001, is scheduled to commence production in the second quarter of 2004. The estimated initial gross production rate is 12 MMcfpd. Noble Energy has a 40 percent working interest in Loon. The reserves on this property were recorded in 2001 after a flow test of the well.

Noble Energy had several significant deep shelf properties commence production in 2003. State Lease 340 A-1 (Mound Point), a natural gas discovery in which the Company has a 25 percent working interest, commenced production in the fourth quarter at a gross rate of 850 Bopd and 28 MMcfpd. Viosca Knoll 251 A-3 and A-4 commenced production in the second quarter at a combined gross rate of 26 MMcfpd. Noble Energy has a 40 percent working interest in these wells. South Timbalier 316 (Roaring Fork) commenced production in the third quarter from the discovery well at an initial gross rate of 6,000 Bopd and 13 MMcfpd. During February 2004, the field's gross production was 19,600 Bopd and 40 MMcfpd. The Company has a 40 percent working interest in Roaring Fork.

During 2003, the Company expensed four exploratory wells related to its offshore activity.

Noble Energy was the successful bidder, alone or with partners, on five of seven blocks at the Central Gulf of Mexico Outer Continental Shelf Sale 185. Of the five approved bids, two were on blocks in deepwater, one on a block in the deep shelf and the remaining blocks were on the conventional shelf. Approved bids totaled approximately $2.9 million net to the Company's interest. Noble Energy will be the designated operator on all five of the approved bids.

The Company also participated in the Western Gulf of Mexico Outer Continental Shelf Sale 187. Noble Energy was the successful bidder, alone or with partners, on five of seven blocks. Of the five approved bids, three were on blocks in deepwater and the remaining blocks were on the conventional shelf. Approved bids totaled approximately $2.3 million net to the Company's interest. Noble Energy will be the designated operator on all five of the approved bids.

Domestic Onshore. During 2003, Noble Energy's onshore drilling program included 80 gross (50.4 net) exploration and development wells. Of the wells drilled in 2003, 50 wells, or 63 percent, were commercial discoveries and 30 wells were dry holes.

The Gulf Coast remains one of Noble Energy's most active areas. During 2003, the Company drilled 45 wells in the Gulf Coast with a 53 percent success rate. The Aspect Resources joint venture accounted for a substantial portion of Noble Energy's drilling activity during 2003 with 26 wells drilled and 13 successes.

Noble Energy had a three well program on its Wildcat Ridge project, located in Jefferson County, Texas. Two of the three wells drilled were successful, and additional prospects will be drilled in 2004. The two successful wells were producing 771 BOE per day, gross, at year-end 2003. The Company has a 37.5 percent working interest in the Wildcat Ridge project.

In south Louisiana, Noble Energy drilled and completed a discovery well and successful offset on the Savanne D'Or prospect in Lafourche Parish. The wells were producing 2,400 BOE per day, gross, at year-end 2003. The Company owns a 40 percent working interest in the prospect.

In Duval County, Texas, Noble Energy drilled six wells, of which five were successful. The prospects were identified with proprietary 3D seismic acquired in late 2002. The five successful wells were producing 2,100 BOE per day, gross, at year-end 2003. Noble Energy's working interests in the wells drilled in 2003 range from 85 percent to 100 percent.

During 2003, the Company expensed 22 exploratory wells related to its onshore activity.

Argentina. Noble Energy participated with a 13 percent working interest in 55 development wells in the El Tordillo field during 2003. The Company has been awarded and is awaiting final government approval on a crude oil and natural gas exploration permit of approximately 1.2 million acres. The permit is located adjacent to an existing permit in the Cuyo Basin of Mendoza Province in western Argentina.

China. Noble Energy has a 57 percent working interest in the Cheng Dao Xi ("CDX") field, which is located on the south side of Bohai Bay off the coast of China. Initial production from CDX commenced on January 13, 2003. During 2003, CDX averaged 5,781 Bopd (3,295 Bopd net to Noble Energy).

During 2003, the Company expensed two exploratory wells related to its block 16/02 activity in China. The 16/02 block was subsequently relinquished during the year. Noble Energy also relinquished its acreage in the Cheng Zi Kou field during 2003.

Ecuador. In September 2002, Noble Energy commenced operations of its 100 percent-owned integrated gas-to-power project. The project includes the Amistad field, which is located in the shallow waters of the Gulf of Guayaquil near the coast of Ecuador. The power plant is located on the coast near Machala, Ecuador and connects to the Amistad field via a 40-mile pipeline. The Machala power plant is the only natural gas-fired commercial power generator in Ecuador and currently has a generating capacity of 130 MW of electricity from twin General Electric Frame 6Fa turbines. Additional development drilling is planned for 2004.

Equatorial Guinea. During 2002, Noble Energy and its partners obtained approval from the government of Equatorial Guinea for Phases 2A and 2B Alba field expansion projects. The Phase 2A project includes adding two platforms, 12 wells, three pipelines and two compressors. The processed dry gas is then re-injected into the reservoir. Initial startup of Phase 2A began in November 2003. The Phase 2A expansion is expected to increase gross condensate production approximately 27,700 Bpd (8,400 Bpd net to Noble Energy).

Phase 2B, scheduled to be completed late in the fourth quarter of 2004, is expected to increase gross production of LPG by approximately 14,000 Bpd (3,900 Bpd net to Noble Energy) and gross condensate production by approximately 6,000 Bpd (1,800 Bpd net to Noble Energy). The project includes increasing processing capacity, storage and offloading facilities at the existing LPG plant. A fractionation unit will also be installed.

Following the ramp-up of Phase 2A in 2004 and the completion of Phase 2B, gross condensate and LPG capacity will be approximately 52,000 Bpd (15,800 Bpd net to Noble Energy) and 16,700 Bpd (4,700 Bpd net to Noble Energy), respectively.

Noble Energy, through its subsidiaries, holds a 34 percent working interest in the Alba field and related condensate production facilities, a 28 percent working interest in the Bioko Island LPG plant and a 45 percent working interest in the AMPCO plant. The AMPCO plant purchases and processes approximately 125 MMcfpd of natural gas into 2,500 MTpd of methanol.

Israel. The Company and its partners have an agreement to provide approximately 170 MMcfpd of natural gas for use in IEC's power plants. Natural gas will be produced from the Mari-B field, offshore Israel, which was discovered in 2000. Sales commenced February 18, 2004. Noble Energy has a 47 percent working interest in the project.

North Sea. The Company continued to focus on production and exploration growth in 2003 and added reserves in producing fields. The Company participated in two non-operated discoveries in the North Sea. Both discoveries are expected to lead to development. The Company plans to drill one exploration well in 2004.

Vietnam. In December 2003, Noble Energy elected not to pursue any additional exploration efforts in the Nam Con Son Basin of Vietnam. As a result, the Company wrote off its investment in Vietnam and is in the process of assigning its ownership in the two blocks. During 2003, the Company expensed one exploratory well and associated exploration costs.

Net Exploratory and Development Wells. The following table sets forth, for each of the last three years, the number of net exploratory and development wells drilled by or on behalf of Noble Energy. An exploratory well is a well drilled to find and produce crude oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir. A development well, for purposes of the following table and as defined in the rules and regulations of the SEC, is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, to the reporting of abandonment to the appropriate agency.

	Net Exploratory Wells				*Net Development Wells*			
	Productive(1)		*Dry(2)*		*Productive(1)*		*Dry(2)*	
Year Ended December 31,	*U.S.*	*Int'l*	*U.S.*	*Int'l*	*U.S.*	*Int'l*	*U.S.*	*Int'l*
2003	10.84	.07	12.40	2.67	25.10	7.32	8.16	
2002	9.78		11.45	3.27	41.53	12.84	11.17	
2001	4.87	.63	10.79	5.41	68.30	13.67	12.88	1.62

(1) A productive well is an exploratory or a development well that is not a dry hole.

(2) A dry hole is an exploratory or development well determined to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

At January 31, 2004, Noble Energy was drilling 9 gross (4.1 net) exploratory wells and 3 gross (.4 net) development wells. These wells are located onshore in California, Louisiana, Nevada, Texas and Argentina and offshore in the Gulf of Mexico. These wells have objectives ranging from approximately 4,500 feet to 21,500 feet. The drilling cost to Noble Energy of these wells will be approximately $20.5 million if all are dry and approximately $43.8 million if all are completed as producing wells.

Crude Oil and Natural Gas Wells. Due to the various asset dispositions in 2003, there was a significant decrease from 2002 in the number of gross wells in which Noble Energy held an interest. The number of productive crude oil and natural gas wells in which Noble Energy held an interest as of December 31 follows:

	2003(1)(2)		*2002(1)(2)*		*2001(1)(2)*	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*
Crude Oil Wells						
United States – Onshore	196.0	118.2	1,131.0	458.7	1,364.5	573.6
United States – Offshore	186.0	114.2	232.5	95.7	212.5	120.0
International	716.0	88.8	687.0	81.3	670.0	75.7
Total	1,098.0	321.2	2,050.5	635.7	2,247.0	769.3
Natural Gas Wells						
United States – Onshore	1,645.0	1,042.1	1,603.0	1,006.6	1,673.5	1,025.7
United States – Offshore	299.0	116.5	265.5	184.9	333.5	143.3
International	34.0	8.4	42.0	13.1	38.0	8.4
Total	1,978.0	1,167.0	1,910.5	1,204.6	2,045.0	1,177.4

(1) Productive wells are producing wells and wells capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

(2) One or more completions in the same borehole are counted as one well in this table.

The following table summarizes multiple completions and non-producing wells as of December 31 for the years shown. Included in wells not producing are productive wells awaiting additional action, pipeline connections or shut-in for various reasons.

	2003		*2002*		*2001*	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*
Multiple Completions						
Crude Oil	9.0	5.8	12.0	6.0	13.5	6.9
Natural Gas	29.0	11.3	28.5	8.9	36.5	14.0
Not Producing (Shut-in)						
Crude Oil	573.0	109.2	565.0	212.3	391.0	179.2
Natural Gas	337.0	142.5	121.0	73.0	100.0	36.3

At year-end 2003, Noble Energy had less than nine percent of its crude oil and natural gas sales volumes committed to long-term supply contracts and had no similar agreements with foreign governments or authorities.

Since January 1, 2003, no crude oil or natural gas reserve information has been filed with, or included in any report to any federal authority or agency other than the SEC and the Energy Information Administration ("EIA"). Noble Energy files Form 23, including reserve and other information, with the EIA.

The SEC requested clarification, which the Company provided, as to the Company's Israel and Equatorial Guinea gas reserves recorded in excess of existing contract amounts. SEC guidelines do not limit reserve bookings only to contracted volumes if it can be demonstrated that there is reasonable certainty that a market exists, which the Company believes exists in both of these situations. The Israel gas contract is for a period of 11 years. The Israel gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is twenty times greater than Noble

Energy's uncontracted net estimated proved reserves. In Equatorial Guinea, the gas contract, which runs through 2026, is between the field owners and the methanol plant owners. Noble Energy, through its subsidiaries, holds a working interest in the field as well as an interest in the methanol plant. The Company has recorded reserves through the end of the concession's term in 2040. Noble Energy has obtained independent third-party engineer reserve estimates for both of these projects.

Average Sales Price. The following table sets forth, for each of the last three years, the average sales price per unit of crude oil produced and per unit of natural gas produced, and the average production cost per unit from continuing operations.

	Year Ended December 31,		
	2003	*2002(6)*	*2001(6)*
Average sales price per Bbl of crude oil (1):			
United States	$26.21	$23.29	$23.02
International	$28.94	$24.98	$23.98
Combined (2)	$27.72	$24.22	$23.49
Average sales price per Mcf of natural gas (1):			
United States	$ 4.75	$ 3.24	$ 4.21
International (3)	$ 1.17	$ 1.18	$ 1.60
Combined (4)	$ 4.13	$ 2.89	$ 3.86
Average production cost per Mcfe (5):			
United States	$ .74	$ .63	$ .61
International	$ .78	$ .43	$ .39
Combined	$ .75	$ .57	$ .56

(1) Net production amounts used in this calculation include royalties.

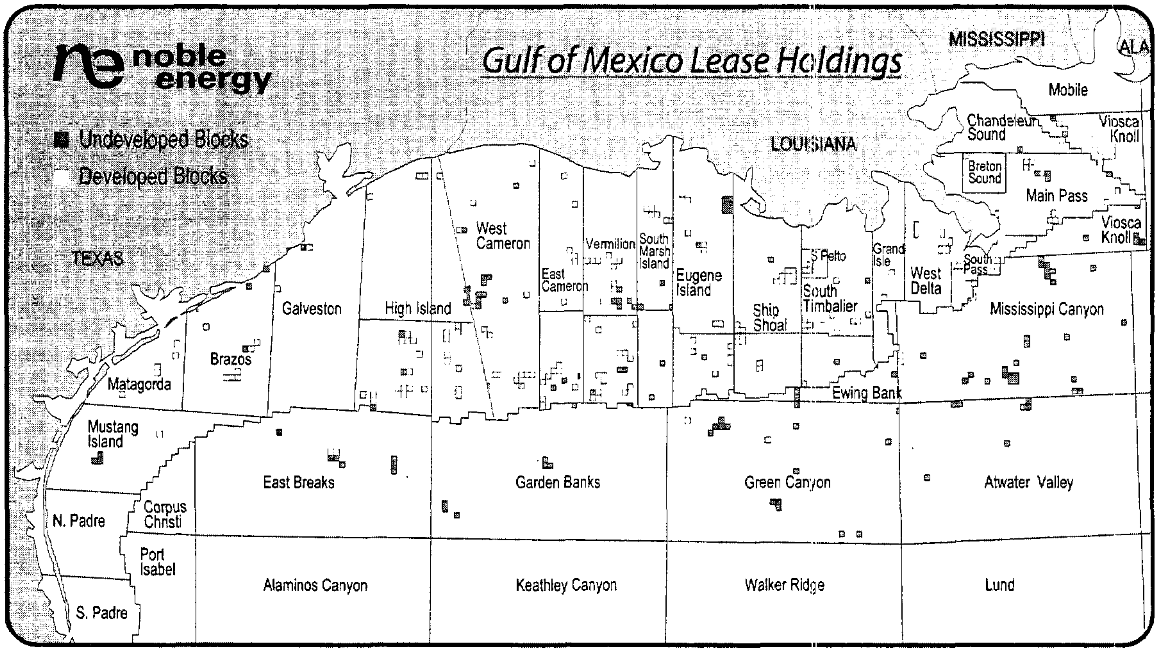
(2) Reflects a reduction of $1.01 per Bbl in 2003, $.02 per Bbl in 2002 and an increase of $.01 per Bbl in 2001 from hedging in the United States.

(3) Ecuador natural gas revenues and natural gas production volumes are excluded in the calculation of the International average sales price per Mcf of natural gas. The gas-to-power project in Ecuador is 100 percent owned by Noble Energy. Intercompany natural gas sales are eliminated for accounting purposes.

(4) Reflects a reduction of $.44 per Mcf in 2003, an increase of $.05 per Mcf in 2002 and $.04 per Mcf in 2001 from hedging in the United States.

(5) Production costs include lease operating expense, workover expense, production taxes and other related lifting costs. The natural gas production volumes associated with the Company's gas-to-power project in Ecuador for 2003 and 2002 were 7,842 MMcf and 2,788 MMcf, respectively, and are excluded in the average production cost per Mcfe for both International and Combined.

(6) Reclassified from prior years due to discontinued operations.



Significant Offshore Undeveloped Lease Holdings (interests rounded to nearest whole percent)

Block	*Working Interest (%)*
East Breaks	
279 *	33
464 *	48
465 *	48
475 *	100
510 *	33
519 *	100
563 *	100
Green Canyon	
23	100
85 *	50
142	100
185 *	100
186 *	100
187 *	100
199 *	20
228 *	100
303 *	40
507 *	50
723 *	100
724 *	100
768 *	100
955 *	7
958 *	25
West Cameron	
136	40
311	10
392	100
393	100
400	100
419	100
422	50
423	100
438	100
443	100
446	100
Mustang Island	
829	80
830	80
831	100
Vermilion	
208	25
227	100
228	100
230	100
232	50
235	100
352	100
353	100
391	100
Garden Banks	
25	50
416 *	100
460 *	100
461 *	100
751 *	100
795 *	100
841 *	39
Main Pass	
107	25
109	25
110	25
192	100
East Cameron	
342	67
348	30
355	100
South Timbalier	
62	100
278	50
Ship Shoal	
73	50
Galveston	
249-L	50
South Marsh Island	
38	100
64	67
70	50
145	100
195	50
Mississippi Canyon	
26 *	75
70 *	75
71 *	75
115 *	75
116 *	100
123 *	75
159 *	75
204 *	100
524 *	50
595 *	24
602 *	75
639 *	24
665 *	50
769 *	100
811 *	30
849 *	34
855 *	30
856 *	30
857 *	30
892 *	35
896 *	67
900 *	30
901 *	30
911 *	40
999 *	30
1000 *	30
Brazos	
308-L	50
543	100
Ewing Bank	
834	14
949	52
993	98
Eugene Island	
35	25
36	25
37	25
38	25
96	25
317	67
High Island	
A-218	100
A-230	100
A-232	50
A-422	100
A-516	100
A-587	3
Viosca Knoll	
23	100
157	100
697	50
908 *	100
917 *	10
961 *	10
962 *	10
Atwater Valley	
10 *	100
11 *	100
23 *	100
66 *	100
67 *	100
327 *	79
533 *	40

*Located in water deeper than 1,000 feet.

The developed and undeveloped acreage (including both leases and concessions) that Noble Energy held as of December 31, 2003, is as follows:

	Developed Acreage (1)(2)		*Undeveloped Acreage (2)(3)(4)*	
Location	*Gross Acres*	*Net Acres*	*Gross Acres*	*Net Acres*
United States Onshore				
Alabama			2,926	505
California	2,368	1,191	5,914	2,610
Colorado	79,251	60,372	27,636	20,817
Kansas	93,278	52,833	18,724	12,828
Louisiana	33,712	11,398	36,920	11,465
Michigan			1,876	427
Mississippi	878	34	1,884	51
Montana	201,622	122,928	4,598	1,612
Nevada			50,996	49,727
New Mexico	2,117	826	2,480	1,833
North Dakota			685	314
Oklahoma	137,943	48,756	12,752	5,833
Texas	88,076	33,952	114,190	46,331
Utah	1,280	260	3,232	2,456
Wyoming	27,183	11,834	66,388	35,973
Total United States Onshore	667,708	344,384	351,201	192,782
United States Offshore (Federal Waters)				
Alabama	97,920	37,670	24,381	14,467
California	38,833	12,039	52,364	9,422
Louisiana	543,986	239,863	443,042	285,774
Mississippi	37,756	19,260	120,960	58,070
Texas	214,325	97,702	114,911	76,625
Total United States Offshore (Federal Waters)	932,820	406,534	755,658	444,358
International				
Argentina	28,988	3,977	2,426,221	2,353,455
China	7,413	4,225	1,617,549	808,775
Denmark			81,050	32,420
Ecuador	12,355	12,355	851,771	851,771
Equatorial Guinea	45,203	15,727	266,754	92,808
Israel	123,552	58,142	292,572	137,681
Netherlands	865	130	74,749	11,212
United Kingdom	65,489	4,441	418,039	110,641
Vietnam (5)			1,701,812	1,309,034
Total International	283,865	98,997	7,730,517	5,707,797
Total (6)	1,884,393	849,915	8,837,376	6,344,937

(1) Developed acreage is acreage spaced or assignable to productive wells.

(2) A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

(3) Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves. Included within undeveloped acreage are those leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well so holding such lease.

(4) The Argentina acreage includes one concession totaling 1,163,865 acres subject to final regulatory approval.

(5) The Company wrote off its investment in Vietnam and is in the process of assigning its ownership in the two blocks.

(6) If production is not established, approximately 112,617 gross acres (65,080 net acres), 136,362 gross acres (85,015 net acres) and 128,939 gross acres (79,699 net acres) will expire during 2004, 2005 and 2006, respectively.

Item 3. Legal Proceedings.

The Company and its subsidiaries are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters and does not believe that the ultimate disposition of such proceedings will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

On October 15, 2002, Noble Gas Marketing, Inc. and Samedan Oil Corporation, collectively referred to as the "Noble Defendants," filed proofs of claim in the United States Bankruptcy Court for the Southern District of New York in response to bankruptcy filings by Enron Corporation and certain of its subsidiaries and affiliates, including Enron North America Corporation ("ENA"), under Chapter 11 of the U.S. Bankruptcy Code. The proofs of claim relate to certain natural gas sales agreements and aggregate approximately $12 million.

On December 13, 2002, ENA filed a complaint in which it objected to the Noble Defendants' proofs of claim, sought recovery of approximately $60 million from the Noble Defendants under the natural gas sales agreements, sought declaratory relief in respect of the offset rights of the Noble Defendants and sought to invalidate the arbitration provisions contained in certain of the agreements in issue. The Noble Defendants intend to vigorously defend against ENA's claims and do not believe that the ultimate disposition of the bankruptcy proceeding will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

On January 13, 2003, the Noble Defendants filed an answer to ENA's complaint. On January 29, 2003, the Noble Defendants filed the Motion of Noble Energy Marketing, Inc., as Successor to Noble Gas Marketing, Inc., and Noble Energy, Inc., as Successor to Samedan Oil Corporation, to Compel Arbitration. On March 4, 2003, the Court issued its Order Governing Mediation of Trading Cases and Appointing the Honorable Allan L. Gropper as Mediator (the "Mediation Order") which, among other things, abated this case and referred it to mediation along with other pending adversary proceedings in the Enron bankruptcy cases which involve disputes arising from or in connection with commodity trading contracts. Pursuant to the Mediation Order, the Honorable Allan L. Gropper (United States Bankruptcy Judge for the Southern District of New York) is acting as mediator for this case and the other trading cases which have been referred to him. The mediation for this case was held on December 17, 2003 and no resolution was reached.

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to a vote of security holders during the fourth quarter of 2003.

Executive Officers of the Registrant

The following table sets forth certain information, as of March 12, 2004, with respect to the executive officers of the Registrant.

Name	Age	Position
Charles D. Davidson (1)	54	Chairman of the Board, President, Chief Executive Officer and Director
Alan R. Bullington (2)	52	Vice President, International
Robert K. Burleson (3)	46	Vice President, Business Administration and President, Noble Energy Marketing, Inc.
Susan M. Cunningham (4)	48	Senior Vice President, Exploration
Arnold J. Johnson (5)	48	Vice President, General Counsel and Secretary
James L. McElvany (6)	50	Senior Vice President, Chief Financial Officer and Treasurer
Richard A. Peneguy, Jr. (7)	53	Vice President, Offshore
William A. Poillion, Jr. (8)	54	Senior Vice President, Production and Drilling
Ted A. Price (9)	44	Vice President, Onshore
David L. Stover (10)	46	Vice President, Business Development
Kenneth P. Wiley (11)	51	Vice President, Information Systems

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(1) Charles D. Davidson was elected President and Chief Executive Officer of the Company in October 2000 and Chairman of the Board in April 2001. Prior to October 2000, he served as President and Chief Executive Officer of Vastar Resources, Inc. ("Vastar") from March 1997 to September 2000 (Chairman from April 2000) and was a Vastar Director from March 1994 to September 2000. From September 1993 to March 1997, he served as a Senior Vice President of Vastar. From December 1992 to October 1993, he was Senior Vice President of the Eastern District for ARCO Oil and Gas Company. From 1988 to December 1992, he held various positions with ARCO Alaska, Inc. Mr. Davidson joined ARCO in 1972.

(2) Alan R. Bullington was elected Vice President and General Manager, International Division of Samedan Oil Corporation on January 1, 1998 and on April 24, 2001 was elected a Vice President of the Company. Prior thereto, he served as Manager-International Operations and Exploration and as Manager-International Operations. Prior to his employment with Samedan in 1990, he held various management positions within the exploration and production division of Texas Eastern Transmission Company.

(3) Robert K. Burleson was elected a Vice President of the Company on April 24, 2001 and has been in charge of the Company's Business Administration Department since April 2002. He has also served as President of Noble Gas Marketing, Inc. (now Noble Energy Marketing, Inc.) since June 14, 1995. Prior thereto, he served as Vice President-Marketing for Noble Gas Marketing since its inception in 1994. Previous to his employment with the Company, he was employed by Reliant Energy as Director of Business Development for its interstate pipeline, Reliant Gas Transmission.

(4) Susan M. Cunningham was elected Senior Vice President of Exploration of the Company in April 2001. Prior to joining the Company, Ms. Cunningham was Texaco's Vice President of worldwide exploration from April 2000 to March 2001. From 1997 through 1999, she was employed by Statoil, beginning in 1997 as Exploration Manager for deepwater Gulf of Mexico, appointed a Vice President in 1998 and responsible, in 1999, for Statoil's West Africa exploration efforts. She joined Amoco in 1980 as a geologist and served in exploration and development positions of increasing responsibility until 1997.

(5) Arnold J. Johnson was elected Vice President, General Counsel and Secretary of the Company on February 1, 2004. Prior thereto, he served as Associate General Counsel and Assistant Secretary of the Company from January 2001 through January 2004. Prior thereto, he served as Senior Counsel for BP America, Inc. from October 2000 to January 2001. Mr. Johnson held several positions as an attorney for Vastar Resources, Inc. and ARCO from March 1989 through September 2000, most recently as Assistant General Counsel and Assistant Secretary of Vastar Resources from 1997 through 2000. He joined ARCO in 1980 as a landman and served in land management positions of increasing responsibility until 1989.

(6) James L. McElvany was elected Senior Vice President, Chief Financial Officer and Treasurer of the Company in July 2002. Prior thereto, he served as Vice President-Finance, Treasurer and Assistant Secretary since July 1999. Prior to July 1999, he had served as Vice President-Controller of the Company since December 1997. Prior thereto, he served as Controller of the Company since December 1983.

(7) Richard A. Peneguy, Jr. was elected a Vice President of the Company on April 24, 2001 and has served as Vice President and General Manager, Offshore Division of Samedan Oil Corporation since January 2002. Prior thereto, he served as Vice President and General Manager, Onshore Division of Samedan since January 2000. Prior thereto, he served as General Manager, Onshore Division of Samedan since January 1, 1991.

(8) William A. Poillion, Jr. was elected a Senior Vice President of the Company on April 24, 2001 and has served as Senior Vice President-Production and Drilling of Samedan Oil Corporation since January 1998. Prior thereto, he served as Vice President-Production and Drilling of Samedan since November 1990. From March 1, 1985 to October 31, 1990, he served as Manager of Offshore Production and Drilling for Samedan.

(9) Ted A. Price was elected Vice President of the Company and Division Manager for the Onshore Division on January 29, 2002. Previously, he served as Manager of Onshore Exploration since 1999. Mr. Price joined the Company in 1981 as a geologist.

(10) David L. Stover was elected Vice President of Business Development of the Company on December 16, 2002. Previous to his employment with the Company, he was employed by BP as Vice President, Gulf of Mexico Shelf from September 2000 to August 2002. Prior to joining BP, Mr. Stover was employed by Vastar Resources, Inc. as Area Manager for Gulf of Mexico Shelf from April 1999 to September 2000, and prior thereto, as Area Manager for Oklahoma/Arklatex from January 1994 to April 1999.

(11) Kenneth P. Wiley was elected Vice President-Information Systems of the Company in July 1998. Prior thereto, he served as Manager-Information Systems for Samedan Oil Corporation since November 1994.

Officers serve until the next annual organizational meeting of the Board of Directors or until their successors are chosen and qualified. No officer or executive officer of the Registrant currently has an employment agreement with the Registrant or any of its subsidiaries. There are no family relationships among any of the Registrant's officers.

PART II

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

Common Stock. The Registrant's Common Stock, $3.33 1/3 par value ("Common Stock"), is listed and traded on the New York Stock Exchange under the symbol "NBL." The declaration and payment of dividends are at the discretion of the Board of Directors of the Registrant and the amount thereof will depend on the Registrant's results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors.

Stock Prices and Dividends by Quarters. The following table sets forth, for the periods indicated, the high and low sales price per share of Common Stock on the New York Stock Exchange and quarterly dividends paid per share.

	High	*Low*	*Dividends Per Share*
2003			
First quarter	$38.62	$33.07	$.04
Second quarter	$40.02	$32.37	$.04
Third quarter	$40.00	$35.37	$.04
Fourth quarter	$45.99	$37.48	$.05
2002			
First quarter	$40.00	$30.76	$.04
Second quarter	$40.76	$34.70	$.04
Third quarter	$36.34	$26.65	$.04
Fourth quarter	$40.50	$31.55	$.04

Transfer Agent and Registrar. The transfer agent and registrar for the Common Stock is Wachovia Bank, N.A., NC1153, 1525 West W. T. Harris Blvd., 3C3, Charlotte, North Carolina 28262-1153.

Stockholders' Profile. Pursuant to the records of the transfer agent, as of March 5, 2004, the number of holders of record of Common Stock was 998. The following chart indicates the common stockholders by category.

March 5, 2004	*Shares Outstanding*
Individuals	381,843
Joint accounts	56,013
Fiduciaries	118,890
Institutions	64,807
Nominees	57,176,142
Foreign	319
Total-Excluding Treasury Shares	57,798,014

Sales of Unregistered Securities. The Company owns a 45 percent interest in AMPCO through its 50 percent ownership in AMCCO. During 1999, AMCCO issued $125 million Series A-2 senior secured notes due December 15, 2004 to fund construction payments owed in connection with the construction of the methanol plant. The Company includes the $125 million Series A-2 senior notes on its balance sheet. At the same time the Series A-2 Notes were issued, the Company guaranteed the payment of interest on the Series A-2 Notes and issued, in a private placement pursuant to Section 4(2) of the Securities Act, 125,000 shares of its Series B Mandatorily Convertible Preferred Stock (the "Series B Preferred Stock"), par value $1.00 per share to Noble Share Trust, which is a Delaware statutory business trust, in exchange for all of the beneficial ownership interests in the Noble Share Trust.

Noble Share Trust holds the 125,000 shares of Series B Preferred Stock for the benefit of the holders of the Series A-2 Notes. The Series A-2 indenture trustee, and the holders of 25 percent of the outstanding principal amount of the Series A-2 Notes, would have the right to require a public offering of the Series B Preferred Stock to generate proceeds sufficient to repay the Series A-2 Notes, upon the occurrence of certain events ("Trigger Dates"), including (i) defaults under the Indenture governing the Series A-2 Notes, (ii) a default and acceleration of the Company's debt exceeding five percent of the Company's consolidated net tangible assets, and (iii) the simultaneous occurrence of a downgrade of the Company's unsecured senior debt rating to "Ba1" or below by Moody's or "BB+" or below by Standard & Poor's and a decline in the closing price of the Company's common stock for three consecutive trading days to below $17.50. The exercise of this mandatory remarketing right is subject to certain forbearance provisions that would allow the Company the opportunity to obtain funds for the repayment of the Series A-2 Notes by alternative means for a specified period of time.

The terms of the Series B Preferred Stock, including dividend and conversion features, would be reset at the time of the remarketing, based on the recommendation of Credit Suisse First Boston, as Remarketing Agent, as to the terms necessary to generate proceeds to repay the Series A-2 Notes. If the Remarketing Agent is not able to complete a registered public offering of the Series B Preferred Stock, it may under certain circumstances conduct a private placement of such stock. If it were impossible for legal reasons to remarket the Series B Preferred Stock, the Company would be obligated to repay the Series A-2 Notes.

The Series B Preferred Stock would be mandatorily convertible into the Company's common stock three years after remarketing (or failed remarketing). Generally, each share of Series B Preferred Stock would then be mandatorily convertible at the "Mandatory Conversion Rate," which is equal to the following number of shares of the Company's common stock:

(a) if the Mandatory Conversion Date Market Price is greater than or equal to the Threshold Appreciation Price, the quotient of (i) $1,000 divided by (ii) the Threshold Appreciation Price;

(b) if the Mandatory Conversion Date Market Price is less than the Threshold Appreciation Price but is greater than the Reset Price, the quotient of $1,000 divided by the Mandatory Conversion Date Market Price; and

(c) if the Mandatory Conversion Date Market Price is less than or equal to the Reset Price, the quotient of $1,000 divided by the Reset Price.

"Mandatory Conversion Date Market Price" means the average closing price per share of the Company's common stock for the 20 consecutive trading days immediately prior to, but not including, the mandatory conversion date.

"Threshold Appreciation Price" means the product of (i) the Reset Price (as the same may be adjusted from time to time) and (ii) 110 percent.

"Reset Price" means the higher of (i) the closing price of a share of the Company's common stock on the Trigger Date or (ii) the quotient (rounded up to the nearest cent) of $125,000,000 divided by the number, as of the Trigger Date, of the authorized but unissued shares of common stock that have not been reserved as of the Trigger Date by the Company's Board of Directors for other purposes.

In addition to the mandatory conversion discussed above, each share of the Series B Preferred Stock is generally convertible, at the option of the holder thereof at any time before the mandatory conversion date, into 36.364 shares of the Company's common stock (the "Optional Conversion Rate"); provided, however, that the Optional Conversion Rate shall adjust, as of the earlier to occur of remarketing or failed remarketing, to the quotient of (i) $1,000 divided by (ii) the Threshold Appreciation Price.

Item 6. Selected Financial Data.

(in thousands, except per share amounts and ratios)	Year Ended December 31, 2003	2002	2001	2000	1999
Revenues and Income					
Revenues	$1,010,986	$ 702,578	$ 789,513	$ 730,657	$ 558,887
Net cash provided by operating activities	602,770	506,955	628,154	562,578	343,935
Income from continuing operations	89,892	8,095	85,163	137,066	28,110
Net income	77,992	17,652	133,575	191,597	49,461
Per Share Data					
Basic earnings per share:					
Income from continuing operations	$ 1.58	$ 0.14	$ 1.51	$ 2.45	$ 0.49
Net income	$ 1.37	$ 0.31	$ 2.36	$ 3.42	$ 0.87
Cash dividends	$ 0.17	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Year-end stock price	$ 44.43	$ 37.55	$ 35.29	$ 46.00	$ 21.44
Basic weighted average shares outstanding	56,964	57,196	56,549	55,999	57,005
Financial Position (at year end)					
Property, plant and equipment, net:					
Oil and gas mineral interests, equipment and facilities	$2,099,741	$2,139,785	$1,953,211	$1,485,123	$1,242,370
Total assets	2,842,649	2,730,015	2,604,255	2,002,819	1,543,023
Long-term obligations:					
Long-term debt, net of current portion	776,021	977,116	961,118	648,567	567,524
Deferred income taxes	163,146	201,939	176,259	117,048	83,075
Other	50,654	69,820	75,629	61,639	53,877
Shareholders' equity	1,073,573	1,009,386	1,010,198	849,682	683,609
Ratio of debt-to-book capital (1)	.46	.50	.50	.44	.46

(1) Defined as the Company's total debt plus its equity.

For additional information, see "Item 8. Financial Statements and Supplementary Data" of this Form 10-K.

Operating Statistics – Continuing Operations

	Year Ended December 31, 2003	2002	2001	2000	1999
Natural Gas					
Sales (in millions)	$ 457.6	$ 341.1	$ 487.4	$ 492.0	$ 327.6
Production (MMcfpd)	336.6	341.0	355.6	335.8	386.6
Average realized price (per Mcf)	$ 4.13	$ 2.89	$ 3.86	$ 4.09	$ 2.40
Crude Oil					
Sales (in millions)	$ 358.0	$ 252.3	$ 208.6	$ 124.9	$ 124.0
Production (Bopd)	36,014	29,114	24,973	19,650	23,690
Average realized price (per Bbl)	$ 27.72	$ 24.22	$ 23.49	$ 18.21	$ 14.72
Royalty sales (in millions)	$ 23.5	$ 15.6	$ 20.9	$ 17.3	$ 14.0

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

Noble Energy is an independent energy company engaged, directly or through its subsidiaries or various arrangements with other companies, in the exploration, development, production and marketing of crude oil and natural gas. The Company has exploration, exploitation and production operations domestically and internationally. The domestic areas consist of: offshore in the Gulf of Mexico and California; the Gulf Coast Region (Louisiana and Texas); the Mid-Continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, Nevada, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel), the North Sea (Denmark, the Netherlands and the United Kingdom) and Vietnam. The Company also markets domestic crude oil and natural gas production through a wholly-owned subsidiary, NEMI.

The Company's accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

EXECUTIVE OVERVIEW

Noble Energy's principal business strategy is to create shareholder value by generating stable cash flow and production from domestic operations, while generating growth from international projects. In the U.S., the Company has a substantial onshore and offshore asset base located in established, prolific basins where the Company is aggressively pursuing exploration and exploitation opportunities. Offshore, exploration focuses on the deepwater and deep shelf areas of the Gulf of Mexico. Internationally, the Company has built a strong project portfolio and has applied innovative approaches to developing markets for stranded natural gas, including construction of a natural gas-fired power plant near Machala, Ecuador, and liquefied petroleum gas and methanol plants in Equatorial Guinea.

Over the past two years, the Company has completed major, capital-intensive projects in Ecuador, China, Israel and the first phase of a two-phase project in Equatorial Guinea. With these important projects completed, international capital commitments are declining rapidly. At the same time, the projects are contributing significantly to the Company's financial and operating results.

During 2003, Noble Energy reached several milestones in positioning the Company as a major international competitor among independent exploration and production companies, including:

- First production in China occurred in January 2003;
- Initial production began in November 2003 from the Phase 2A expansion project in Equatorial Guinea;
- Facilities were commissioned to begin production of natural gas in Israel, with first production in December 2003 and first sales in February 2004; and
- Full year of Ecuador power plant operations.

Domestically, an active onshore drilling program led to several discoveries and new production during 2003. Offshore, in the deepwater region of the Gulf of Mexico, the Company announced an apparent discovery on the Lorien prospect and start of production from the Boris field. In the shelf region of the Gulf of Mexico, there was new production from the Roaring Fork field beginning in the fourth quarter. Also during 2003, the Company identified and prepared for sale five packages of domestic non-core properties. This divestiture program was intended to reduce costs and streamline the business. At the close of the year, sales were completed on four of the property packages.

2003 was a year of strong financial performance as well:

- Net income for 2003 was $78.0 million, a significant increase over 2002 net income of $17.7 million;
- Net cash provided by operating activities in 2003 was $602.8 million, an increase of $95.8 million over net cash provided by operating activities of $507.0 million in 2002; and
- The Company ended the year with a stronger balance sheet -- total debt was $929.7 million, net of unamortized discount, at year-end 2003, a reduction of $89.3 million from the previous year.

With 2003's strong financial performance and the decline in international capital commitments, Noble Energy gained enhanced financial flexibility. Projects in China, Ecuador and Israel are now complete. In Equatorial Guinea, the first phase production is ramping up and the second phase is scheduled for completion by year-end 2004. The completion of these projects should contribute to increased amounts of free cash flow. Domestic operations have implemented disciplined business processes that have stabilized production. As a result, Noble Energy has gained financial and operational flexibility.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements requires management of the Company to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of the Company's accounting estimates and judgments which management believes are most significant in its application of generally accepted accounting principles used in the preparation of the consolidated financial statements.

Reserves – All of the reserve data in this Form 10-K are estimates. The Company's estimates of crude oil and natural gas reserves are prepared by the Company's engineers in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Estimates of proved crude oil and natural gas reserves significantly affect the Company's depreciation, depletion and amortization ("DD&A") expense. For example, if estimates of proved reserves decline, the Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves would also trigger an impairment analysis and could result in an impairment charge.

The SEC requested clarification, which the Company provided, as to the Company's Israel and Equatorial Guinea gas reserves recorded in excess of existing contract amounts. SEC guidelines do not limit reserve bookings only to contracted volumes if it can be demonstrated that there is reasonable certainty that a market exists, which the Company believes exists in both of these situations. The Israel gas contract is for a period of 11 years. The Israel gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is twenty times greater than Noble Energy's uncontracted net estimated proved reserves. In Equatorial Guinea, the gas contract, which runs through 2026, is between the field owners and the methanol plant owners. Noble Energy, through its subsidiaries, holds a working interest in the field as well as an interest in the methanol plant. The Company has recorded reserves through the end of the concession's term in 2040. Noble Energy has obtained independent third-party engineer reserve estimates for both of these projects.

Oil and Gas Properties – The Company accounts for its crude oil and natural gas properties under the successful efforts method of accounting. The alternative method of accounting for crude oil and natural gas properties is the full cost method. Under the successful efforts method, costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties are amortized to operations by the unit-of-production method based on proved developed crude oil and natural gas reserves on a property-by-property basis as estimated by Company engineers. Application of the successful efforts method results in the expensing of certain costs including geological and geophysical costs, exploratory dry holes and delay rentals, during the periods the costs are incurred. Under the full cost method, these costs are capitalized as assets and charged to earnings in future periods as a component of DD&A expense. The Company believes the successful efforts method is the most appropriate method to use to account for its crude oil and natural gas production activities because during periods of active exploration, this method results in a more conservative measurement of net assets and net income. If the Company had used the full cost method, its financial position and results of operations would have been significantly different.

Impairment of Oil and Gas Properties – The Company assesses proved crude oil and natural gas properties for possible impairment when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. The Company recognizes an impairment loss when the estimated undiscounted future cash flows from a property are less than the current net book value. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs can result in a reduction in undiscounted future cash flows and could indicate a property impairment. The Company recognized $31.9 million of impairments in 2003, primarily related to a reserve revision on a property in the Gulf of Mexico after recompletion and remediation activities produced less-than-expected results.

The Company also performs periodic assessments of individually significant unproved crude oil and natural gas properties for impairment. Management's assessment of the results of exploration activities, estimated future commodity prices and operating costs, availability of funds for future activities and the current and projected political climate in areas in which the Company operates impact the amounts and timing of impairment provisions. In December 2003, the Company elected not to pursue any additional exploration efforts in the Nam Con Son Basin of Vietnam. As a result, the Company wrote off its investment in Vietnam.

Asset Retirement Obligation – The Company's asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and gas properties. Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A. At December 31, 2003, the Company's balance sheet included a liability for ARO of $124.5 million.

Derivative Instruments and Hedging Activities – The Company uses various derivative financial instruments to hedge its exposure to price risk from changing commodity prices. The Company does not enter into derivative or other financial instruments for trading purposes. Management exercises significant judgment in determining types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties and their creditworthiness. The Company accounts for its derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." For derivative instruments that qualify as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in accumulated other comprehensive income ("AOCI") until the forecasted transaction is recognized in earnings. Therefore, prior to settlement of the derivative instruments, changes in the fair market value can cause significant increases or decreases in AOCI. For derivative instruments that do not qualify as cash flow hedges, changes in fair value must be reported in the current period, rather than in the period in which the forecasted transaction occurs. This may result in significant increases or decreases in current period net income.

Deferred Tax Asset Valuation Allowance – The Company's balance sheet includes deferred tax assets related to deductible temporary differences and operating loss carryforwards. Ultimately, realization of a deferred tax benefit depends on the existence of sufficient taxable income within the carryback/carryforward period to absorb future deductible temporary differences or a carryforward. In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. As a result of management's current assessment, the Company maintains a valuation allowance against a portion of its deferred tax assets. The valuation allowances associated with certain foreign loss carryforwards have decreased from $21.1 million in 2002 to $14.5 million in 2003. This change was due to the elimination of the carryforward and offsetting valuation allowance associated with Vietnam, the elimination of the valuation allowance associated with Israel and the partial elimination of the valuation allowance associated with China. Because of the relatively short carryforward period in China and the lack of a long-term fixed price contract, the valuation allowance associated with China was not fully eliminated. The Company will continue to monitor facts and circumstances in its reassessment of the likelihood that operating loss carryforwards and other deferred tax attributes will be utilized prior to their expiration. As a result, the Company may determine that the deferred tax asset valuation allowance should be increased or decreased. Such changes would impact net income through offsetting changes in income tax expense.

Pension Plan – The Company sponsors a defined benefit pension plan and other postretirement benefit plans. The actuarial determination of the projected benefit obligation and related benefit expense requires that certain assumptions be made regarding such variables as expected return on plan assets, discount rates, rate of compensation increase, estimated employee turnover rates and retirement dates, lump-sum election rates, mortality rate, retiree utilization rates for health care services and health care cost trend rates. The selection of assumptions requires considerable judgment concerning future events and has a significant impact on the amount of the obligation recorded on the Company's balance sheets and on the amount of expense included on the Company's statements of operations, as well as on funding.

Noble Energy bases its determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2003, the Company had cumulative asset losses of approximately $7.0 million, which remain to be recognized in the calculation of the market-related value of assets.

The Company utilizes the services of an outside actuarial firm to assist in the calculations of the projected benefit obligation and related costs. The Company and its actuaries use historical data and forecasts to determine assumptions. In selecting the assumption for expected long-term rate of return on assets, the Company considers the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. It is assumed that the long-term asset mix will be consistent with the target asset allocation of 70 percent equity and 30 percent fixed income, with a range of plus or minus 10 percent acceptable degree of variation in the plan's asset allocation. The discount rate is determined by analyzing the interest rates implicit in current annuity contract prices and available yields on high quality fixed income securities. By definition, discount rates reflect rates at which pension benefits could be effectively settled.

The expected return assumption for 2004 is 8.5 percent and the assumed discount rate for 2004 is 6.25 percent, both of which are the same as 2003.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The Company's primary cash needs are to fund capital expenditures related to the acquisition, exploration and development of crude oil and natural gas properties, to repay outstanding borrowings or to pay other contractual commitments, for interest payments on debt, to pay cash dividends on common stock and to fund contributions to the

Company's pension and postretirement benefit plans. The Company's traditional sources of liquidity are its cash on hand, cash flows from operations and available borrowing capacity under its credit facilities. Funds may also be generated from occasional sales of non-strategic crude oil and natural gas properties. The Company made significant progress during 2003 in improving liquidity and financial flexibility. Reduction in international capital commitments due to completion of major capital-intensive projects is expected to increase flexibility and liquidity in 2004. With these projects completed or nearing completion, international capital commitments are declining rapidly while, at the same time, they are beginning to contribute to the Company's financial and operating results. A $100 million increase in the Company's 364-day credit facility will also provide increased liquidity in 2004.

The Company improved its balance sheet leverage during 2003 and achieved a reduction in its ratio of debt-to-book capital (defined as the Company's total debt plus its equity) to 46 percent at December 31, 2003, compared to 50 percent at December 31, 2002. The Company reduced total debt by $89.3 million during 2003.

The Company's current ratio (current assets divided by current liabilities) was .73:1 at December 31, 2003, compared with .66:1 at December 31, 2002. The improvement in the current ratio in 2003, as compared to 2002, resulted from increases in year-end cash and cash equivalents, accounts receivable and derivative financial instruments in current assets which were partially offset by increases in accounts payable, current installments of long-term debt and derivative financial instruments in current liabilities. In 2003, total current assets increased by 54 percent as compared to 2002 while total current liabilities increased only 39 percent for the same period.

Cash Flows

Operating Activities – The Company reported a $95.8 million year-over-year increase in cash flows from operating activities. Net cash provided by operating activities totaled $602.8 million for the year ended December 31, 2003, compared to $507.0 million in 2002 and $628.2 million in 2001. The 2003 increase was driven by an overall production increase of four percent and higher realized commodity prices. The increase was also impacted by higher distributions from the Company's unconsolidated methanol subsidiary and a growing contribution from electricity sales. The $121.2 million decrease in 2002, as compared to 2001, was due primarily to lower natural gas prices, partially offset by higher crude oil prices and production volumes.

Investing Activities – Net cash used in investing activities totaled $444.8 million, $577.5 million and $871.7 million for the years ending December 31, 2003, 2002 and 2001, respectively. The Company's investing activities relate primarily to expenditures made for the exploration and development of oil and gas properties and have been decreasing due to declining capital commitments. During 2003, expenditures were offset by the receipt of $81.1 million from sales of non-core assets. Additionally, the Company funded the Aspect acquisition in 2001 for approximately $97.8 million, net of $9.3 million cash acquired and 405,778 shares of treasury stock.

Financing Activities – Net cash used in financing activities totaled $111.0 million for the year ending December 31, 2003. Net cash provided by financing activities totaled $12.8 million and $293.6 million for the years ending December 31, 2002 and 2001, respectively. Financing activities consist primarily of proceeds from and repayments of bank debt, repayment of notes payable, the payment of cash dividends and proceeds from the exercise of stock options. Also included in financing activities was the repayment of an obligation of $36.6 million related to treasury stock in 2003. The decrease in net cash provided by financing activities in 2003 as compared to 2002 resulted from repayments of bank debt and repayment of the treasury stock obligation in addition to a decrease in bank borrowings. The decrease in net cash provided by financing activities in 2002 as compared to 2001 related primarily to a decrease in bank borrowings.

Capital Expenditures

Capital expenditures incurred in oil and gas activities, downstream projects, acquisitions, and corporate and other consisted of the following:

	Year Ended December 31,		
(in thousands)	*2003*	*2002*	*2001*
Oil and gas mineral interests, equipment and facilities	$ 492,764	$ 543,967	$ 667,499
Downstream projects	45,134	57,646	95,716
Aspect acquisition			97,792
Corporate and other	6,119	3,185	1,932
Total capital expenditures (1)	$ 544,017	$ 604,798	$ 862,939

(1) Total capital expenditures include seismic, lease rentals and other miscellaneous expenditures, which are expensed through the statements of operations and are not included in capital expenditures from investing activities.

Capital expenditures from investing activities consisted of the following:

	Year Ended December 31,		
(in thousands)	*2003*	*2002*	*2001*
Capital expenditures (1)	$ 527,386	$ 595,739	$ 738,706
Aspect acquisition, net of cash acquired			97,792
Total capital expenditures from investing activities	$ 527,386	$ 595,739	$ 836,498

(1) Capital expenditures do not include expenditures for the methanol plant. Those expenditures are included in cash flows from investing activities – investment in unconsolidated subsidiaries.

Capital expenditures budget	$ 510,000	$ 519,000	$ 625,000

Capital expenditures have shown year-over-year declines of $60.8 million or 10 percent (2003 to 2002) and $258.1 million or 30 percent (2002 to 2001). These decreases in spending are the result of declining capital commitments due to the completion, or near completion, of major capital-intensive projects in international locations.

During 2003, the Company expended $544.0 million compared to a budget of $510 million. The primary reason for the additional capital expenditures was due to the acceleration of the initial costs to begin the Phase 2B expansion in Equatorial Guinea. During 2002, the Company expended $604.8 million compared to a budget of $519 million. The primary additional capital expenditures were for the completion of the gas-to-power project in Ecuador and the continued development of the Israel project. During 2001, the Company expended $862.9 million compared to a budget of $625 million. The primary additional expenditures in 2001 were for the Aspect acquisition, which was $97.8 million and not included in the budget, and the completion of the methanol plant in Equatorial Guinea, along with the development of the gas-to-power project in Ecuador.

2004 Budget – The Company's 2004 capital expenditure budget totals $459.7 million, a decline of 15 percent compared to 2003 actual capital expenditures. The reduced budget results from the completion of two major international projects, the Phase 2A condensate expansion project in Equatorial Guinea and the Mari-B natural gas project in Israel.

The 2004 capital budget has allocated approximately 35 percent to exploration opportunities and 65 percent to production and development projects. The budget allocates $270.4 million, or 59 percent, to domestic spending with approximately two-thirds for the offshore division and one-third for the onshore division. Of the total domestic capital budget, approximately 55 percent is for exploration and 45 percent is for production and development. The budget allocates $189.3 million, or 41 percent, to international expenditures with 84 percent for production and development projects. Noble Energy has planned expenditures allocated to regions where the Company is most active, including the Middle East and Africa ($95.3 million), the Far East and Latin America ($73.8 million) and the North Sea ($20.2 million). The Company expects that its 2004 capital expenditure budget will be funded primarily from cash flow from operations and proceeds from the sale of its offshore asset package expected to occur during the first half of 2004. The Company will evaluate its level of capital spending throughout the year based upon drilling results, commodity prices, cash flows from operations and property acquisitions.

Acquisitions – The Company has made no significant acquisitions since 2001 when it acquired interests in certain wells located along the Texas and Louisiana Gulf Coast and an interest in future drilling prospects from Aspect Energy for $97.8 million, net of $9.3 million cash acquired and 405,778 shares of treasury stock.

Asset Sales

The Company has sold a number of non-strategic crude oil and natural gas properties over the past three years. Proceeds from asset sales totaled $81.1 million, $20.4 million and $1.4 million in 2003, 2002 and 2001, respectively. Sales of properties during 2003 included reserves of approximately 108 Bcfe, or four percent, of year-end 2002 proved reserves. Sales of properties during 2002 included reserves of approximately 25 Bcfe. The Company believes the disposition of non-strategic properties allows it to concentrate efforts on strategic properties and reduce leverage.

Financing Activities

Debt – The Company's debt totaled $933.7 million at December 31, 2003, of which $776.0 million was long-term with maturities ranging from 2005 to 2097. The Company's $125 million Series A-2 Notes, $7.9 million of the Aspect acquisition note and $20.7 million of Israel debt are due during 2004 and are classified as short-term on the Company's consolidated balance sheets. The Company expects to fund the repayments primarily from a combination of operating cash flows, draw downs of the credit facilities and proceeds from the sale of non-core properties.

The Company has a $400 million credit agreement due November 30, 2006. The credit facility is with certain commercial lending institutions and exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. The interest rate is based upon a Eurodollar rate plus a range of 60 to 145 basis points depending upon the percentage of utilization and credit rating. At December 31, 2003, there was $140 million borrowed against this credit agreement leaving $260 million of unused borrowing capacity.

The Company entered into a new $300 million 364-day credit agreement effective November 3, 2003, which represents an increase in capacity of $100 million over the previous facility. The credit agreement is with certain commercial lending institutions and exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. The interest rate is based upon a Eurodollar rate plus a range of 62.5 to 150 basis points depending upon the percentage of utilization and credit rating. At December 31, 2003, there was $190 million borrowed against this credit agreement leaving $110 million of unused borrowing capacity. The agreement has a maturity date of October 28, 2004 for the revolving commitment and a final maturity date of October 28, 2005 for the term commitment that includes any balance remaining after the revolving commitment matures.

During 2004, a subsidiary of the Company borrowed a total of $150.0 million from certain commercial lending institutions. The interest rate on the borrowing is London Interbank Offering Rate ("LIBOR") plus an effective range of 60 to 130 basis points depending upon credit rating and the borrowing is for a term of five years. Proceeds were used to reduce amounts due under the $400 million credit agreement.

Financial covenants on both the $400 million and $300 million credit facilities include the following: (a) the ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense ("EBITDAX") to interest expense for any consecutive period of four fiscal quarters ending on the last day of a fiscal quarter may not be less than 4.0 to 1.0; (b) the total debt to capitalization ratio, expressed as a percentage, may not exceed 60 percent at any time; and (c) the total asset value of the Company's restricted entities may not be less than $800 million at any time.

The Company occasionally enters into forward contracts or swap agreements to hedge exposure to interest rate risk. At December 31, 2003, the Company's consolidated balance sheet included a payable of $4.0 million related to an outstanding interest rate lock.

The Company made cash interest payments of $46.0 million, $47.6 million and $41.7 million during 2003, 2002 and 2001, respectively.

Dividends – The Company paid quarterly cash dividends of four cents per share from 1989 through the third quarter 2003. In October 2003, the Company's Board of Directors declared a quarterly cash dividend of five cents per common share. This payment represents an increase of one cent per share, or 25 percent, over the Company's previous quarterly payment of four cents per share. Total dividends paid during 2003 increased $.6 million, or seven percent, over 2002 due to the higher dividend rate. The amount of future dividends will be determined on a quarterly basis at the discretion of the Company's Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Stock Repurchase Program – In accordance with a Board-approved stock repurchase forward program, one of the Company's banks purchased 1,044,454 shares of Company stock on the open market during 2001 and 2002. During the second quarter of 2003, the Company adopted SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." As a result, the Company recorded an additional 1,044,454 shares of treasury stock at a cost of $36.6 million and an obligation of $36.6 million. In December 2003, the Company paid the obligation in full.

Exercise of Stock Options – The Company received $24.7 million, $7.7 million and $12.3 million from the exercise of stock options during 2003, 2002 and 2001, respectively. Proceeds received by the Company from the exercise of stock options fluctuate primarily based on the price at which the Company's common stock trades on the New York Stock Exchange in relation to the exercise price of the options issued. During 2003 and 2001, the Company's stock reached higher sales prices than during 2002, resulting in the exercise of more options and more proceeds to the Company. In addition, during 2003, stock options were exercised at a higher average price than during 2001 and 2002.

Other

Contributions to Pension and Other Postretirement Benefit Plans – The Company made contributions of $14.6 million to its pension and other postretirement benefit plans during 2003, $10.9 million during 2002 and $3.7 million during 2001. The Company expects to make cash contributions of $2.0 million to its pension plan during 2004. The decrease in the expected contribution for 2004 is due primarily to the higher actual return on pension plan assets experienced during 2003 and an expectation of a continued positive return on plan assets during 2004 due to the recovery of market conditions. During 2003, the actual return on plan assets was a positive $7.6 million, while the returns in 2002 and 2001 were a negative $3.5 million and a negative $1.5 million, respectively. The value of the plan assets has tended to follow market performance. The expected return assumption for 2004 is 8.5 percent and the assumed discount rate for 2004 is 6.25 percent, both of which are the same as 2003. A one percent decrease in the expected return on plan assets would have resulted in an increase in benefit expense of $.7 million in 2003.

Federal Income Taxes – The Company made cash payments for federal income taxes of $55.5 million during 2003 and $66.1 million during 2001. During 2002, the Company received a federal tax refund of $40.4 million. The refund related to large estimated tax payments made during the first half of 2001 followed by a period of declining commodity prices, which resulted in lower taxable income by the end of 2001.

Contingencies – During 2003, the Company paid $1.9 million in settlement of two legal proceedings conducted in the ordinary course of business. During 2002, the Company paid $7.0 million in settlement of a legal proceeding conducted in the ordinary course of business. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Contractual Obligations

The following table summarizes the Company's contractual obligations as of December 31, 2003.

(in thousands)	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Outstanding debt	$ 933,674	$ 153,674	$ 330,000	$	$ 450,000
Asset retirement obligation	124,537	1,023	63,034	19,489	40,991
Drilling obligations	3,924	3,924			
Building lease	14,292	1,588	4,764	3,176	4,764
Total contractual cash obligations	$ 1,076,427	$ 160,209	$ 397,798	$ 22,665	$ 495,755

In addition, in the ordinary course of business, the Company maintains letters of credit in support of certain performance obligations. Outstanding letters of credit totaled approximately $18 million at December 31, 2003.

RESULTS OF OPERATIONS

Net Income and Revenues

The Company's net income for 2003 was $78.0 million, an increase of $60.3 million from 2002. The increase was due to the following: crude oil sales increased $106.9 million, natural gas sales increased $123.2 million and income from unconsolidated subsidiaries increased $31.1 million. The increases were offset by increased oil and gas operations expense (lease operating expense, workover expense, production taxes and other related lifting costs from continuing operations) of $40.5 million, increased DD&A of $72.5 million, a non-cash impairment of $31.9 million, a $9.3 million increase in accretion of asset retirement obligation, a non-cash pre-tax charge for change in accounting principle of $9.0 million and a $4.8 million increase in selling, general and administrative ("SG&A"). In addition, loss from discontinued operations increased $15.6 million. The decrease of $115.9 million in net income for 2002 compared to 2001 was due to a $151.3 million decrease in natural gas sales, offset by a $43.4 million increase in crude oil sales.

Natural Gas Information

Natural gas revenues increased 35 percent in 2003, compared to 2002, due to a 43 percent increase in natural gas prices, offset by a one percent decrease in daily natural gas production. Natural gas revenues for 2002, compared to 2001, decreased 30 percent due to a 25 percent decrease in natural gas prices coupled with a four percent decrease in daily natural gas production. The table below depicts average daily natural gas production and prices from continuing operations by area for the last three years.

	2003		2002		2001	
	Mcfpd	Price	Mcfpd	Price	Mcfpd	Price
United States	260,560	$ 4.75	280,836	$ 3.24	311,663	$ 4.21
North Sea	13,861	$ 3.86	16,991	$ 3.14	17,830	$ 3.51
Equatorial Guinea (1)	39,906	$ .25	34,382	$ .25	24,488	$ .25
Other International (2)	22,284	$ .41	8,799	$ .38	1,651	$ .95
Total (3)	336,611	$ 4.13	341,008	$ 2.89	355,632	$ 3.86

(1) Natural gas in Equatorial Guinea is under a 25-year contract for $.25 per MMBTU.

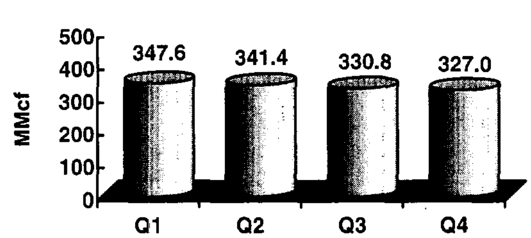
(2) Ecuador natural gas volumes are included in Other International production, but are not included in natural gas sales revenues and average price for 2003 and 2002. Because the gas-to-power project in Ecuador is 100 percent owned by Noble Energy, intercompany natural gas sales are eliminated for accounting purposes.

(3) Reflects a reduction of $.44 per Mcf in 2003, and increases of $.05 per Mcf in 2002 and $.04 per Mcf in 2001 from hedging in the United States.

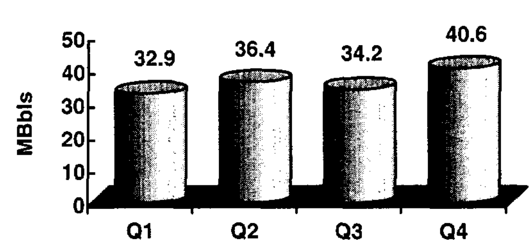
The 51,103 Mcfpd decline in natural gas production for the United States from 2001 to 2003 is the result of reduced domestic drilling and natural decline rates for properties in the Gulf of Mexico and the onshore Gulf Coast region. The 3,969 Mcfpd decline in natural gas production for the North Sea from 2001 to 2003 is the result of natural gas decline rates for properties in the United Kingdom section of the North Sea. The 15,418 Mcfpd increase in natural gas production for Equatorial Guinea from 2001 to 2003 is the result of the startup of the methanol plant in May 2001 and the expansion of the Phase 2A project. The 20,633 Mcfpd increase in natural gas production for Other International from 2001 to 2003 is the result of the startup of the gas-to-power project in Ecuador during 2002.

2003 Daily Production by Quarter

Natural Gas



Crude Oil



Crude Oil Information

Crude oil revenues increased 42 percent during 2003, compared to 2002, due to a 14 percent increase in crude oil prices and a 24 percent increase in daily crude oil production. Crude oil revenues for 2002, compared to 2001, increased 20 percent due to a three percent increase in crude oil prices coupled with a 17 percent increase in daily crude oil production. The table below depicts average daily crude oil production and prices from continuing operations by area for the last three years.

	2003		2002		2001	
	Bopd	Price	Bopd	Price	Bopd	Price
United States	16,084	$26.21	13,187	$23.29	12,926	$23.02
North Sea	7,412	$29.95	7,847	$25.15	4,688	$23.36
Equatorial Guinea	6,377	$27.93	5,259	$23.88	4,620	$23.03
Other International	6,141	$28.75	2,821	$26.58	2,739	$26.67
Total (1)	36,014	$27.72	29,114	$24.22	24,973	$23.49

(1) Reflects a reduction of $1.01 per Bbl in 2003, $.02 per Bbl in 2002 and an increase of $.01 per Bbl in 2001 from hedging in the United States.

The 3,158 Bopd increase in crude oil production for the United States from 2001 to 2003 is the result of success of the Company's deepwater projects in the Gulf of Mexico region. The 2,724 Bopd increase in crude oil production for the North Sea from 2001 to 2003 is the result of commencement of production from the Hanze field, offshore in the Netherlands in late 2001. The 1,757 Bopd increase in crude oil production for Equatorial Guinea from 2001 to 2003 is the result of the continued development of the Alba field and the expansion of the Phase 2A project. The 3,402 Bopd increase in crude oil production for Other International from 2001 to 2003 is the result of the startup of the CDX field, located in South Bohai Bay off the coast of China, in January 2003.

Electricity Sales - Ecuador Integrated Power Project

The Company, through its subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., has a 100 percent ownership interest in an integrated gas-to-power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies fuel to the Machala power plant.

During 2003, the first full year of operations, the combined project generated $7.2 million of operating income from the generation of 751,689 MW of electricity. The average sales price was 7.7 cents per Kwh.

During 2002, after commencement of commercial electricity generation in mid-September, the Machala power plant contributed $2.3 million of operating income from generation of 269,229 MW of electricity. The average sales price was 6.8 cents per Kwh.

Income from Unconsolidated Subsidiaries

Methanol operations produced $40.6 million, $9.5 million and $7.0 million of operating income, net to Noble Energy's interest, during 2003, 2002 and 2001, respectively. AMPCO, an unconsolidated subsidiary in which the Company owns a 45 percent interest, owns a methanol plant in Equatorial Guinea that began production of commercial grade methanol during the second quarter of 2001. The Company's share of AMPCO methanol sales volumes was 122 million gallons in 2003, 105 million gallons in 2002 and 54 million gallons in 2001. Average realized methanol prices were $.65 per gallon, $.43 per gallon and $.39 per gallon for 2003, 2002 and 2001, respectively.

Derivative Financial Instruments and Hedging Activities

The Company, from time to time, uses various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include fixed price hedges, variable to fixed price swaps, costless collars and other contractual arrangements. Although these derivative instruments expose the Company to credit risk, the Company monitors the creditworthiness of its counterparties and believes that losses from nonperformance are unlikely to occur. Hedging gains and losses related to the Company's crude oil and natural gas production are recorded in oil and gas sales and royalties. During 2003, 2002 and 2001, the Company included a $67.5 million reduction of sales and increased sales of $5.9 million and $5.1 million, respectively, related to its cash flow hedges in oil and gas sales and royalties.

Costs and Expenses

Crude oil and natural gas operations expense from continuing operations increased $40.5 million in 2003 compared to 2002. The increase in crude oil and natural gas operating expense was due to several factors, including new operations in China, increased production and the startup of Phase 2A in Equatorial Guinea, new production in the Gulf of Mexico and higher production taxes. Crude oil and natural gas operating expense increased $1.7 million in 2002 compared to 2001.

The table below depicts the crude oil and natural gas operations expense from continuing operations by area for the last three years.

(in thousands)

	Consolidated	United States	North Sea	Israel(2)	Equatorial Guinea	Other Int'l
2003						
Lease operating (1)	$ 120,060	$ 75,356	$ 10,662	$	$ 16,319	$ 17,723
Production taxes	19,473	14,601				4,872
Workover expense	6,303	6,303				
Total operations expense	$ 145,836	$ 96,260	$ 10,662	$	$ 16,319	$ 22,595
2002						
Lease operating (1)	$ 82,168	$ 61,217	$ 10,817	$	$ 9,848	$ 286
Production taxes	14,315	12,284				2,031
Workover expense	8,875	8,880	(5)			
Total operations expense	$ 105,358	$ 82,381	$ 10,812	$	$ 9,848	$ 2,317
2001						
Lease operating (1)	$ 79,733	$ 63,169	$ 6,075	$	$ 6,775	$ 3,714
Production taxes	8,829	8,686				143
Workover expense	15,094	15,094				
Total operations expense	$ 103,656	$ 86,949	$ 6,075	$	$ 6,775	$ 3,857

(1) Lease operating expense includes labor, fuel, repairs, replacements, saltwater disposal, ad valorem taxes and other related lifting costs.

(2) Production did not begin until 2004.

In 2003, DD&A expense from continuing operations increased $72.5 million compared to 2002. The increase was primarily due to higher domestic DD&A rates and increased production volumes. The unit rate of DD&A per BOE was $9.20 in 2003. Included in DD&A for 2003 is $20.6 million of abandoned assets expense and $20.2 million of DD&A related to asset retirement obligations, which increased DD&A by $1.26 per BOE. In 2002, DD&A expense increased

$3.4 million compared to 2001. The unit rate of DD&A per BOE was $7.55 in 2002 and $7.58 in 2001. The table below depicts the DD&A from continuing operations for the years ended December 31:

(in thousands)	*2003*	*2002*	*2001*
United States	$ 254,041	$ 192,708	$ 202,732
North Sea	28,219	28,279	16,537
Israel	40	31	23
Equatorial Guinea	6,115	5,849	3,889
Other International and Corporate	20,928	10,014	10,335
Total DD&A Expense	$ 309,343	$ 236,881	$ 233,516

The Company adopted SFAS No. 143 on January 1, 2003 and recognized, as the fair value of asset retirement obligations, $109.4 million related to the United States and $15.1 million related to the North Sea. Due to the adoption of SFAS No. 143, the Company recognized a charge for this cumulative effect of change in accounting principle of $5.8 million ($9.0 million net of $3.2 million tax). The Company had previously accumulated a provision for future dismantlement and restoration costs of $84.1 million at December 31, 2002. At December 31, 2003, the total asset retirement obligations of $199.3 million consist of $175.9 million for the United States and $23.4 million for the North Sea and are included in future production and development costs for purposes of estimating the future net revenues relating to the Company's proved reserves.

Crude oil and natural gas exploration expense consists of dry hole expense, unproved lease amortization, seismic, staff expense and other miscellaneous exploration expense, including lease rentals. The table below depicts the exploration expense by area for the last three years.

(in thousands)	*Consolidated*	*United States*	*North Sea*	*Israel*	*Equatorial Guinea*	*Other Int'l*
2003						
Dry hole expense	$ 63,637	$ 32,408	$ 4,023	$ 6,711	$	$ 20,495
Unproved lease amortization	33,381	25,296	1,264	900		5,921
Seismic	17,674	15,903	1,662		51	58
Staff expense	30,182	17,483	3,105	214	83	9,297
Other	3,944	3,601	449			(106)
Total exploration expense	$ 148,818	$ 94,691	$ 10,503	$ 7,825	$ 134	$ 35,665
2002						
Dry hole expense	$ 81,396	$ 64,449	$ 544	$	$	$ 16,403
Unproved lease amortization	21,254	19,426	178	900		750
Seismic	20,492	14,282	827	1,671	1,341	2,371
Staff expense	24,928	20,081	2,833	54		1,960
Other	2,631	2,457	828			(654)
Total exploration expense	$ 150,701	$ 120,695	$ 5,210	$ 2,625	$ 1,341	$ 20,830
2001						
Dry hole expense	$ 99,684	$ 54,810	$ 28,992	$	$	$ 15,882
Unproved lease amortization	17,213	15,112	1,725	375		1
Seismic	15,607	13,328	2,209	5	39	26
Staff expense	17,148	14,431	1,605			1,112
Other	2,444	2,811	419			(786)
Total exploration expense	$ 152,096	$ 100,492	$ 34,950	$ 380	$ 39	$ 16,235

Impairment of Operating Assets

The Company recognized $31.9 million of impairments in 2003, primarily related to a reserve revision on the East Cameron 338 field in the Gulf of Mexico after recompletion and remediation activities produced less-than-expected results. An analysis of the performance response of the field resulted in a reduction in proved reserves of 2.2 MMBoe.

The impairment should result in substantially lower depletion costs in 2004. The Company recorded no operating asset impairments during 2002 and 2001. Individually significant unproved crude oil and natural gas properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance.

Selling, General and Administrative Expenses

SG&A expenses increased $4.8 million in 2003 compared to 2002 and increased $3.5 million in 2002 compared to 2001. The increase in SG&A expenses for 2003 is due to increased corporate governance costs, professional fees and other costs related to Sarbanes-Oxley compliance and increased salary expense. The increase in 2002 compared to 2001 is due to increased salary and legal expense, as well as increased costs associated with the Company's international expansion.

Gathering, Marketing and Processing

NEMI markets the majority of the Company's domestic natural gas, as well as certain third-party natural gas. NEMI sells natural gas directly to end-users, natural gas marketers, industrial users, interstate and intrastate pipelines, power generators and local distribution companies. NEMI markets a portion of the Company's domestic crude oil, as well as certain third-party crude oil. The Company records all of NEMI's sales, net of cost of goods sold, as GMP proceeds and NEMI's expenses as GMP. All intercompany sales and expenses have been eliminated in the Company's consolidated financial statements.

The GMP proceeds less expenses for NEMI are reflected in the table below.

(in thousands, except margins)	2003		2002		2001	
(amounts include inter-company eliminations)	Crude Oil	Natural Gas	Crude Oil	Natural Gas	Crude Oil	Natural Gas
Proceeds (1)	$ 31,867	$ 36,291	$ 26,824	$ 37,693	$ 26,359	$ 38,281
Expenses						
Transportation	21,456	28,844	20,323	29,000	19,739	28,818
General and administrative	182	8,632	802	3,857	199	3,176
Total Expenses	$ 21,638	$ 37,476	$ 21,125	$ 32,857	$ 19,938	$ 31,994
Gross Margin	$ 10,229	$ (1,185)	$ 5,699	$ 4,836	$ 6,421	$ 6,287
Traded Volumes - Bbls/MMBTU	8,324	239,311	6,787	276,626	6,748	278,944
Margin per Bbl/MMBTU	$ 1.23	$ (.01)	$ .84	$ .02	$ .95	$ .02

(1) The Company has reclassified all periods to present GMP activities on a net rather than a gross basis in accordance with Emerging Issues Task Force ("EITF") 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts."

NEMI, from time to time, employs various derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to natural gas price risk. Most of the purchases made by NEMI are on an index basis; however, purchasers in the markets in which NEMI sells often require fixed or NYMEX-related pricing. NEMI records gains and losses on derivative instruments using mark-to-market accounting. NEMI recorded a loss of $.2 million, a gain of $.9 million and a loss of $.5 million in GMP proceeds during 2003, 2002 and 2001, respectively, related to derivative instruments.

Interest Expense

Interest rates have consistently decreased over the past three years while Company borrowings have steadily increased, peaking early in 2003. Throughout the remainder of the year, the Company steadily paid down its debt resulting in a year-over-year decrease of $2.9 million in interest expense at December 31, 2003 compared to the same period in

2002. Interest expense totaled $64.0 million at December 31, 2002, which was a $10.0 million increase over interest expense of $54.0 million at December 31, 2001. The Company believes that interest rates will remain stable in 2004 and expects to continue paying down its debt throughout the year, which should result in lower interest expense at year-end 2004.

Pension Expense

The Company recognized net periodic benefit cost related to its pension and other postretirement benefit plans of $7.9 million, $8.5 million and $5.7 million during 2003, 2002 and 2001, respectively. This expense included an expected return on pension plan assets of $5.9 million, $5.5 million and $4.9 million during 2003, 2002 and 2001, respectively.

Allowance for Doubtful Accounts

The Company is exposed to credit risk and takes reasonable steps to protect itself from nonperformance by its debtors, but is not able to predict sudden changes in its debtors' creditworthiness. The Company periodically assesses its provision for bad debt allowance. The Company had allowances for doubtful accounts as of December 31, 2003 and 2002 of $6.3 million and $1.5 million, respectively. The increase in the allowance in 2003 compared to 2002 was due primarily to an allowance of $4.7 million related to financial derivative contracts with one of the Company's counterparties.

Income Taxes

Income tax expense associated with continuing operations increased to $51.7 million in 2003 from $19.8 million in 2002 primarily from the increase in income. However, the effective income tax rate decreased to 36.5 percent in 2003 from 70.9 percent in 2002. During 2003, the Company's income from international operations increased over 2002, but represented a smaller proportion of the Company's total income. Some of the countries in which the international operations were conducted have a higher statutory income tax rate than the United States. Also impacting the effective rate in 2003 was the realization of approximately $15.6 million of tax benefits for certain prior year costs incurred in Israel and Vietnam.

The $45.2 million decrease in income tax expense for 2002 was due to a $122.2 million decrease in income from continuing operations offset by an increase in the effective income tax rate. The effective income tax rate on income from continuing operations increased to 70.9 percent in 2002 from 43.3 percent in 2001. During 2002, a larger proportion of the Company's income was from international operations. Some of the countries in which international operations are conducted have a higher statutory income tax rate than the United States. In the Netherlands, the Company had significantly higher income in 2002 compared to 2001 due primarily to a full year of production from the Hanze field. In Equatorial Guinea, the Company had higher income in 2002 compared to 2001 from a full year of the methanol plant's operations and the impact of nondeductible interest expense. In the United Kingdom, the Company had higher income in 2002 compared to 2001 and was impacted by an increase in the country's corporate tax rate. In Ecuador, the Company had no income prior to 2002.

Discontinued Operations

Pursuant to SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the Company's consolidated financial statements have been reclassified for all periods presented to reflect the operations and assets of the properties being sold as discontinued operations. The net income from discontinued operations was classified on the consolidated statements of operations as "Discontinued Operations, Net of Tax."

During 2003, the Company identified five domestic property packages for disposition. Bids have now been received on all five packages. During 2003, property sales closed on four of the five packages, with the remaining property package expected to close during the first half of 2004. Total pretax proceeds on all five packages, before closing adjustments, are expected to be in excess of $110.0 million.

The Company recorded a loss, net of tax, related to discontinued operations of $6.1 million in 2003. Included in the discontinued operations loss was a $59.2 million ($38.5 million, net of tax) non-cash write down to market value for certain of the five property packages. The Company has reclassified the results of operations associated with the five property packages for 2001 and 2002 to discontinued operations. This reclassification did not have an effect on net income as previously reported for 2001 and 2002. As a result of the reclassification, oil and gas sales and royalties are lower, as well as the associated oil and gas operations and DD&A expense.

Summarized results of discontinued operations are as follows:

	Year ended December 31,		
(dollars in thousands)	*2003*	*2002*	*2001*
Revenues:			
Oil and gas sales and royalties	$ 106,339	$ 91,576	$ 154,873
Costs and Expenses:			
Write down to market value and realized loss	59,171		
Oil and gas operations	27,731	28,468	29,893
Depreciation, depletion and amortization	28,762	48,405	50,500
	115,664	76,873	80,393
Income (Loss) Before Income Taxes	(9,325)	14,703	74,480
Income Tax Provision (Benefit)	(3,264)	5,146	26,068
Income (Loss) From Discontinued Operations	$ (6,061)	$ 9,557	$ 48,412
Key Statistics:			
Daily Production			
Liquids (Bbl)	4,106	4,923	5,688
Natural Gas (Mcf)	32,823	46,615	66,812
Average Realized Price			
Liquids ($/Bbl)	$ 27.71	$ 22.57	$ 22.55
Natural Gas ($/Mcf)	$ 5.41	$ 3.00	$ 4.43

The long-term debt of the Company is recorded at the consolidated level and is not reflected by each component. Thus, the Company has not allocated interest expense to the discontinued operations.

FUTURE TRENDS

The Company expects crude oil and natural gas production from continuing operations to increase in 2004 and 2005 compared to 2003 assuming commodity prices stay in the range experienced in 2003. The increased production in 2004 is expected primarily from ramp-up of the Phase 2A expansion of the Alba field in Equatorial Guinea and the initial sales from the Mari-B field, offshore Israel. The increase in 2005 is expected primarily from the continued expansion of markets in Israel and the Phase 2B expansion of the LPG plant in Equatorial Guinea.

The Company recently set its 2004 capital expenditures budget at approximately $459.7 million. Such expenditures are planned to be funded principally through internally generated cash flows. The Company believes that it has the capital structure to take advantage of strategic acquisitions, as they become available, through internally generated cash flows or available lines of credit and other borrowing opportunities.

Management believes that the Company is well positioned with its balanced reserves of crude oil and natural gas and downstream projects. The uncertainty of commodity prices continues to affect the crude oil, natural gas and methanol industries. The Company cannot predict the extent to which its revenues will be affected by inflation, government regulation or changing prices.

Impact of Recently Issued Accounting Pronouncements

In December 2003, the SEC issued Staff Accounting Bulletin ("SAB") No. 104, "Revenue Recognition." This SAB revises or rescinds portions of the revenue recognition interpretive guidance included in the SAB codification to make it consistent with current authoritative accounting guidance. The principal revisions relate to revenue recognition guidance no longer necessary due to developments in U.S. generally accepted accounting principles. The pronouncement had no impact on the Company's historical financial statements.

During 2003, the Financial Accounting Standards Board ("FASB") issued several new pronouncements:

SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities that fall within the scope of SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, with certain exceptions, and for hedging relationships designated after June 30, 2003. The adoption of this statement had no impact on the Company's historical financial statements.

SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. During the second quarter of 2003, the Company adopted SFAS No. 150. As a result, the Company recorded an additional 1.04 million shares of treasury stock at a cost of $36.6 million and an obligation of $36.6 million.

SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits - An Amendment of FASB Statements No. 87, 88 and 106," revises employers' disclosures about pension plans and other postretirement benefit plans and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. Most of the requirements are effective for financial statements with fiscal years ending after December 15, 2003. The Company has made additional disclosures in its 2003 financial statements in compliance with SFAS No. 132.

FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51," addresses consolidation by business enterprises of variable interest entities. This Interpretation requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. Special provisions apply to enterprises that have fully or partially applied Interpretation No. 46 prior to issuance of this revised Interpretation. Otherwise, application of this Interpretation is required in financial statements of public entities that have interests in variable interest entities or potential variable interest entities commonly referred to as special-purpose entities for periods ending after December 15, 2003. Application by public entities for all other types of entities is required in financial statements for periods ending after March 15, 2004. The provisions of this Interpretation would be applied if the Company were to acquire an interest in a variable interest entity. The adoption of this statement had no impact on the Company's historical financial statements.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("the Act") became law. The Act introduces a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. FASB Staff Position 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," allows deferral of the recognition of the Act's provisions until authoritative guidance on the accounting for the federal subsidy is issued. The Company has elected to defer recognition of the effects of the Act in the accounting for and disclosure of its postretirement benefit plan in accordance with the Staff Position. Authoritative guidance on accounting for the federal subsidy is pending. Final guidance could require the Company to change previously reported information. The Company does not believe that the effects of the Act will have a material adverse impact on its financial condition or results of operations.

Accounting for Costs Associated with Mineral Rights

During 2003, a reporting issue arose regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting crude oil and natural gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. The EITF has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how Noble Energy classifies these assets. Historically, the Company has included the costs of mineral rights associated with extracting crude oil and natural gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, net of amortization, the Company most likely would be required to reclassify certain amounts out of oil and gas properties and into a separate intangible assets line item. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules.

If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, Noble Energy would be required to reclassify the estimated amounts as follows:

	December 31,	
Intangible Assets (in thousands)	*2003*	*2002*
Proved leasehold acquisition costs	$ 835,738	$ 1,083,103
Unproved leasehold acquisition costs	127,194	153,789
Total leasehold acquisition costs	962,932	1,236,892
Less: accumulated depletion	(496,227)	(554,932)
Net leasehold acquisition costs	$ 466,705	$ 681,960

Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on compliance with covenants under the Company's debt agreements.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk.

Cash Flow Hedges – The Company, from time to time, uses various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include fixed price hedges, variable to fixed price swaps, costless collars and other contractual arrangements. Although these derivative instruments expose the Company to credit risk, the Company takes reasonable steps to protect itself from nonperformance by its counterparties including periodic assessment of necessary provisions for bad debt allowance; however, the Company is not able to predict sudden changes in its counterparties' creditworthiness. The Company accounts for its derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and has elected to designate its derivative financial instruments as cash flow hedges. Derivative financial instruments designated as cash flow hedges are reflected at fair value on the Company's consolidated balance sheets. Changes in fair value, to the extent the hedge is effective, are reported in AOCI until the forecasted transaction occurs. Gains and losses from such derivatives related to the Company's crude oil and natural gas production and which qualify for hedge accounting treatment are recorded in oil and gas sales and royalties on the Company's consolidated statements of operations upon sale of the associated products. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative instrument's fair value. Any ineffective portion of the derivative instrument's change in fair value is recognized immediately in other income.

During 2003, 2002 and 2001, the Company entered into various crude oil and natural gas fixed price swaps, costless collars and costless collar combinations related to its crude oil and natural gas production. The tables below depict the various transactions.

Natural Gas	*2003*	*2002*	*2001*
Hedge MMBTUpd	190,038	170,274	16,947
Fixed price range			\$5.23 - \$5.41
Floor price range	\$3.25 - \$3.80	\$2.00 - \$3.50	\$3.25 - \$5.00
Ceiling price range	\$4.00 - \$5.25	\$2.45 - \$5.10	\$4.60 - \$6.25
Percent of daily production	56%	50%	5%
Gain (loss) per Mcf	(\$.44)	\$.05	\$.04

Crude Oil	*2003*	*2002*	*2001*
Hedge Bpd	15,793	5,247	126
Fixed price			\$27.81
Floor price range	\$23.00 - \$27.00	\$23.00 - \$24.00	
Ceiling price range	\$27.20 - \$35.05	\$29.30 - \$30.10	
Percent of daily production	44%	18%	.5%
Gain (loss) per Bbl	(\$1.01)	(\$.02)	\$.01

During 2003, 2002 and 2001, the Company included a reduction of \$67.5 million and gains of \$5.9 million and \$5.1 million, respectively, related to its cash flow hedges in oil and gas sales and royalties. During 2003, 2002 and 2001, no gains or losses were reclassified into earnings as a result of the discontinuance of hedge accounting treatment. During 2003, the Company recorded \$.5 million of ineffectiveness related to its cash flow hedges. No ineffectiveness was recorded for 2002 and 2001.

In 2001, the Company only had financial derivatives in the fourth quarter. Of these fourth quarter derivatives, 25,000 MMBTU of natural gas per day was terminated early. Amounts in AOCI were reclassified into earnings in the same periods during which the hedged forecasted transaction affected earnings, resulting in an increase in oil and gas sales and royalties of \$6.3 million during the fourth quarter of 2001. As a result, the Company recognized an additional \$.70 per MMBTU on the 25,000 MMBTU of natural gas per day in 2001.

As of December 31, 2003, the Company had entered into costless collars related to its natural gas and crude oil production to support the Company's investment program as follows:

	Natural Gas		Crude Oil	
Production Period	MMBTUpd	Price Per MMBTU Floor - Ceiling	Bopd	Price Per Bbl Floor - Ceiling
1Q 2004	120,000	\$4.81 - \$7.77	15,000	\$25.33 - \$31.53
2Q 2004	120,000	\$4.06 - \$5.95	15,000	\$24.83 - \$31.22
3Q 2004	120,000	\$4.19 - \$5.99	15,000	\$25.00 - \$31.13
4Q 2004	120,000	\$4.19 - \$6.42	5,000	\$24.00 - \$30.00

The contracts entitle the Company (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the last scheduled NYMEX trading day applicable for each calculation period is less than the floor price. The Company would pay the counterparty if the settlement price for the last scheduled NYMEX trading day applicable for each calculation period is more than the ceiling price. The amount payable by the floating price payor, if the floating price is above the ceiling price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the ceiling price in respect of each calculation period. The amount payable by the fixed price payor, if the floating price is below the floor price, is the product of the notional quantity per calculation period and the excess, if any, of the floor price over the floating price in respect of each calculation period.

Accumulated Other Comprehensive Income (Loss) – As of December 31, 2003 and 2002, the balance in AOCI included net deferred losses of $7.6 million and $14.6 million, respectively, related to crude oil and natural gas derivative instruments accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefit of $4.1 million and $7.9 million, respectively.

If commodity prices were to stay the same as they were at December 31, 2003, approximately $11.2 million of deferred losses related to the fair values of crude oil and natural gas derivative instruments included in AOCI at December 31, 2003 would be reclassified to earnings during the next twelve months as the forecasted transactions occur, and would be recorded as a reduction in oil and gas sales and royalties. Any actual increase or decrease in revenues will depend upon market conditions over the period during which the forecasted transactions occur. All forecasted transactions currently being hedged with crude oil and natural gas derivative instruments designated as cash flow hedges are expected to occur by December 2004.

Other Derivative Instruments – In addition to the derivative instruments pertaining to the Company's production as described above, NEMI, from time to time, employs various derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to natural gas price risk. Most of the purchases made by NEMI are on an index basis; however, purchasers in the markets in which NEMI sells often require fixed or NYMEX-related pricing. NEMI may use a derivative to convert the fixed or NYMEX sale to an index basis thereby determining the margin and minimizing the risk of price volatility.

NEMI records gains and losses on derivative instruments using mark-to-market accounting. 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. NEMI recorded a loss of $.2 million, a gain of $.9 million and a loss of $.5 million in GMP proceeds during 2003, 2002 and 2001, respectively, related to derivative instruments.

Receivables/Payables Related to Crude Oil and Natural Gas Derivative Financial Instruments – At December 31, 2003, the Company's consolidated balance sheet included a receivable of $56.1 million and a payable of $67.6 million related to crude oil and natural gas derivative financial instruments. At December 31, 2002, the Company's consolidated balance sheet included a receivable of $10.3 million and a payable of $32.3 million related to crude oil and natural gas derivative financial instruments.

During 2003, the Company had contracts with Enron North America Corporation ("ENA") that resulted in gains of $6.9 million (net of allowance) included in GMP proceeds. In addition, as of December 31, 2003, the Company had NYMEX-related transactions with ENA totaling 149 contracts with a mark-to-market receivable value of $1.8 million.

Interest Rate Lock – The Company occasionally enters into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCI, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At December 31, 2003, the Company's consolidated balance sheet included a payable of $4.0 million related to an outstanding interest rate lock. The amount of deferred loss included in AOCI at December 31, 2003 was $2.6 million, net of tax.

The Company has a $400 million credit agreement that exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. The interest rate is based upon a Eurodollar rate plus a range of 60 to 145 basis points depending upon the percentage of utilization and credit rating. At December 31, 2003, there was $140 million borrowed against this credit agreement with an interest rate of 2.19 percent and a maturity date of November 30, 2006. A 10 percent change in the December 31, 2003 interest rate on this $140 million would result in a change in interest expense of $.3 million.

The Company has a new $300 million credit agreement that exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. The interest rate is based upon a Eurodollar rate plus a range of 62.5 to 150 basis points depending upon the percentage of utilization and credit rating. At December 31, 2003, there was $190 million borrowed against this credit agreement with an interest rate of 2.09 percent and a final maturity date of October 28, 2005. A 10 percent change in the December 31, 2003 interest rate on this $190 million would result in a change in interest expense of $.4 million. All other significant Company long-term debt is fixed-rate and, therefore, does not expose the Company to the risk of earnings or cash flow loss due to changes in market interest rates.

The Company does not enter into foreign currency derivatives. The U.S. dollar is considered the primary currency for each of the Company's international operations. Transactions that are completed in a foreign currency are translated into U.S. dollars and recorded in the financial statements. Translation gains or losses were not material in any of the periods presented and the Company does not believe it is currently exposed to any material risk of loss on this basis. Such gains or losses are included in other income on the statements of operations. However, certain sales transactions are concluded in foreign currencies and the Company, therefore, is exposed to potential risk of loss based on fluctuation in exchange rates from time to time.

Cautionary Statement for Purposes of the Private Securities Litigation Reform Act of 1995 and Other Federal Securities Laws

General. Noble Energy is including the following discussion to generally inform its existing and potential security holders of some of the risks and uncertainties that can affect the Company and to take advantage of the "safe harbor" protection for forward-looking statements afforded under federal securities laws. From time to time, the Company's management or persons acting on management's behalf make forward-looking statements to inform existing and potential security holders about the Company. These statements may include, but are not limited to, projections and estimates concerning the timing and success of specific projects and the Company's future: (1) income, (2) crude oil and natural gas production, (3) crude oil and natural gas reserves and reserve replacement and (4) capital spending. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Sometimes the Company will specifically describe a statement as being a forward-looking statement. In addition, except for the historical information contained in this Form 10-K, the matters discussed in this Form 10-K are forward-looking statements. These statements by their nature are subject to certain risks, uncertainties and assumptions and will be influenced by various factors. Should any of the assumptions underlying a forward-looking statement prove incorrect, actual results could vary materially.

Noble Energy believes the factors discussed below are important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made herein or elsewhere by the Company or on its behalf. The factors listed below are not necessarily all of the important factors. Unpredictable or unknown factors not discussed herein could also have material adverse effects on actual results of matters that are the subject of forward-looking statements. Noble Energy does not intend to update its description of important factors each time a potential important factor arises. The Company advises its stockholders that they should: (1) be aware that important factors not described below could affect the accuracy of our forward-looking statements, and (2) use caution and common sense when analyzing our forward-looking statements in this document or elsewhere. All of such forward-looking statements are qualified in their entirety by this cautionary statement.

Volatility and Level of Hydrocarbon Commodity Prices. Historically, natural gas and crude oil prices have been volatile. These prices rise and fall based on changes in market supply and demand fundamentals and changes in the political, regulatory and economic climates and other factors that affect commodities markets generally and are outside of Noble Energy's control. Some of Noble Energy's projections and estimates are based on assumptions as to the future prices of natural gas and crude oil. These price assumptions are used for planning purposes. The Company expects its assumptions may change over time and that actual prices in the future may differ from our estimates. Any substantial or extended change in the actual prices of natural gas and/or crude oil could have a material effect on: (1) the Company's financial position and results of operations, (2) the quantities of natural gas and crude oil reserves that the Company can economically produce, (3) the quantity of estimated proved reserves that may be attributed to its properties, and (4) the Company's ability to fund its capital program.

Production Rates and Reserve Replacement. Projecting future rates of crude oil and natural gas production is inherently imprecise. Producing crude oil and natural gas reservoirs generally have declining production rates. Production rates depend on a number of factors, including geological, geophysical and engineering issues, weather, production curtailments or restrictions, prices for natural gas and crude oil, available transportation capacity, market demand and the political, economic and regulatory climates. Another factor affecting production rates is Noble Energy's ability to replace depleting reservoirs with new reserves through exploration success or acquisitions. Exploration success is difficult to predict, particularly over the short term, where results can vary widely from year to year. Moreover, the Company's ability to replace reserves over an extended period depends not only on the total volumes found, but also on the cost of finding and developing such reserves. Depending on the general price environment for natural gas and crude oil, Noble Energy's finding and development costs may not justify the use of resources to explore for and develop such reserves.

Reserve Estimates. Noble Energy's forward-looking statements are predicated, in part, on the Company's estimates of its crude oil and natural gas reserves. All of the reserve data in this Form 10-K or otherwise made by or on behalf of the Company are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved natural gas and crude oil reserves. Projecting future rates of production and timing of future development expenditures is also inexact. Many factors beyond the Company's control affect these estimates. In addition, the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Therefore, estimates made by different engineers may vary. The results of drilling, testing and production after the date of an estimate may also require a revision of that estimate, and these revisions may be material. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered.

Laws and Regulations. Noble Energy's forward-looking statements are generally based on the assumption that the legal and regulatory environments will remain stable. Changes in the legal and/or regulatory environments could have a material effect on the Company's future results of operations and financial condition. Noble Energy's ability to economically produce and sell crude oil, natural gas, methanol and power is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the U.S. and laws and regulations of foreign nations, affecting: (1) crude oil and natural gas production, (2) taxes applicable to the Company and/or its production, (3) the amount of crude oil and natural gas available for sale, (4) the availability of adequate pipeline and other transportation and processing facilities, and (5) the marketing of competitive fuels. The Company's operations are also subject to extensive federal, state and local laws and regulations in the U.S. and laws and regulations of foreign nations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Noble Energy's forward-looking statements are generally based upon the expectation that the Company will not be required, in the near future, to expend cash to comply with environmental laws and regulations that are material in relation to its total capital expenditures program. However, inasmuch as such laws and regulations are frequently changed, the Company is unable to accurately predict the ultimate financial impact of compliance.

Drilling and Operating Risks. Noble Energy's drilling operations are subject to various risks common in the industry, including cratering, explosions, fires and uncontrollable flows of crude oil, natural gas or well fluids. In addition, a substantial amount of the Company's operations are currently offshore, domestically and internationally, and subject to the additional hazards of marine operations, such as loop currents, capsizing, collision, and damage or loss from severe weather. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including drilling conditions, pressure or irregularities in formations, equipment failures or accidents and adverse weather conditions.

Competition. Competition in the industry is intense. Noble Energy actively competes for reserve acquisitions and exploration leases and licenses, for the labor and equipment required to operate and develop crude oil and natural gas properties and in the gathering and marketing of natural gas, crude oil, methanol and power. The Company's competitors include the major integrated oil companies, independent crude oil and natural gas concerns, individual producers, natural gas and crude oil marketers and major pipeline companies, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers, many of whom have greater financial resources than the Company.

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

INDEX TO FINANCIAL STATEMENTS

Consolidated Financial Statements of Noble Energy, Inc.

Financial Statements of Atlantic Methanol Production Company, LLC

Independent Auditors' Report

To the Shareholders and Board of Directors of Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, shareholders' equity and other comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003. These 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.

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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Noble Energy, Inc. and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

KPMG LLP

Houston, Texas
February 26, 2004

CONSOLIDATED BALANCE SHEETS
NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands, except share amounts)	*December 31,* 2003	2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 62,374	$ 15,442
Accounts receivable - trade, net	303,822	232,924
Derivative financial instruments	56,058	10,271
Materials and supplies inventories	11,083	10,663
Other current assets	23,805	41,074
Assets held for sale	21,245	
Total current assets	478,387	310,374
Property, Plant and Equipment, at Cost:		
Oil and gas mineral interests, equipment and facilities (successful efforts method of accounting)	3,875,598	4,285,508
Other	49,389	48,507
	3,924,987	4,334,015
Accumulated depreciation, depletion and amortization	(1,825,246)	(2,194,230)
Total property, plant and equipment, net	2,099,741	2,139,785
Investment in Unconsolidated Subsidiaries	227,669	234,668
Other Assets	36,852	45,188
Total Assets	$ 2,842,649	$ 2,730,015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable - trade	$ 388,428	$ 351,856
Current installments of long-term debt	153,674	41,919
Derivative financial instruments	67,562	32,285
Other current liabilities	38,506	36,159
Income taxes - current	6,548	9,535
Total current liabilities	654,718	471,754
Deferred Income Taxes	163,146	201,939
Asset Retirement Obligation	124,537	
Other Deferred Credits and Noncurrent Liabilities	50,654	69,820
Long-term Debt	776,021	977,116
Commitments and Contingencies		
Shareholders' Equity:		
Preferred stock - par value $1.00; 4,000,000 shares authorized, none issued		
Common stock - par value $3.33 1/3; 100,000,000 shares authorized; 60,744,583 and 59,868,067 shares issued in 2003 and 2002, respectively	202,480	199,558
Capital in excess of par value	431,208	405,271
Accumulated other comprehensive loss	(10,886)	(14,603)
Retained earnings	526,727	458,490
	1,149,529	1,048,716
Less common stock in treasury at cost (December 31, 2003, 3,549,976 shares and December 31, 2002, 2,505,522 shares)	(75,956)	(39,330)
Total shareholders' equity	1,073,573	1,009,386
Total Liabilities and Shareholders' Equity	$ 2,842,649	$ 2,730,015

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

NOBLE ENERGY, INC. AND SUBSIDIARIES

	Year ended December 31,		
(in thousands, except per share amounts)	*2003*	*2002*	*2001*
Revenues:			
Oil and gas sales and royalties	$ 839,144	$ 609,026	$ 716,939
Gathering, marketing and processing	68,158	64,517	64,640
Electricity sales	58,022	18,257	
Income from investment in unconsolidated subsidiaries	40,626	9,532	6,981
Other income	5,036	1,246	953
Total Revenues	1,010,986	702,578	789,513
Costs and Expenses:			
Oil and gas operations	145,836	105,358	103,656
Transportation	14,679	16,441	16,012
Oil and gas exploration	148,818	150,701	152,096
Gathering, marketing and processing	59,114	53,982	51,932
Electricity generation	50,846	15,946	
Depreciation, depletion and amortization	309,343	236,881	233,516
Impairment of operating assets	31,937		
Selling, general and administrative	52,466	47,664	44,164
Accretion of asset retirement obligation	9,331		
Interest	61,111	64,040	53,960
Interest capitalized	(14,134)	(16,331)	(15,953)
Total Costs and Expenses	869,347	674,682	639,383
Income Before Taxes	141,639	27,896	150,130
Income Tax Provision:			
Current	42,975	2,479	5,527
Deferred	8,772	17,322	59,440
Total Tax Provision	51,747	19,801	64,967
Income From Continuing Operations	89,892	8,095	85,163
Discontinued Operations, Net of Tax	(6,061)	9,557	48,412
Cumulative Effect of Change in Accounting Principle, Net of Tax	(5,839)		
Net Income	$ 77,992	$ 17,652	$ 133,575
Basic Earnings (Loss) Per Share:			
Income from continuing operations	$ 1.58	$ 0.14	$ 1.51
Discontinued operations, net of tax	$ (0.11)	$ 0.17	$ 0.85
Cumulative effect of change in accounting principle, net of tax	$ (0.10)	$	$
Net Income	$ 1.37	$ 0.31	$ 2.36
Diluted Earnings (Loss) Per Share:			
Income from continuing operations	$ 1.56	$ 0.14	$ 1.49
Discontinued operations, net of tax	$ (0.10)	$ 0.17	$ 0.84
Cumulative effect of change in accounting principle, net of tax	$ (0.10)	$	$
Net Income	$ 1.36	$ 0.31	$ 2.33
Weighted Average Shares Outstanding:			
Basic	56,964	57,196	56,549
Diluted	57,539	57,763	57,303

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
NOBLE ENERGY, INC. AND SUBSIDIARIES

	Year ended December 31,		
(in thousands)	*2003*	*2002*	*2001*
Cash Flows from Operating Activities:			
Net income	$ 77,992	$ 17,652	$ 133,575
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	309,343	236,881	233,516
Depreciation, depletion and amortization - electricity generation	27,116	8,458	
Dry hole expense	63,637	81,396	99,684
Amortization of unproved leasehold costs	33,380	21,254	17,213
Non-cash effect of discontinued operations	87,933	48,405	50,500
Cumulative effect of change in accounting principle, net of tax	5,839		
(Gain) loss on disposal of assets	17,978	(106)	(2,098)
Deferred income taxes	(31,475)	20,856	63,604
Accretion of asset retirement obligation	9,331		
Income from unconsolidated subsidiaries	(40,626)	(9,532)	(6,981)
Dividends received from unconsolidated subsidiary	46,125	17,696	
Impairment of operating assets	31,937		
Increase (decrease) in other deferred credits	(19,166)	(5,810)	13,990
(Increase) decrease in other	8,336	10,942	(2,224)
Changes in operating assets and liabilities, not including cash:			
(Increase) decrease in accounts receivable	(70,898)	(49,945)	57,973
(Increase) decrease in other current assets	16,849	21,972	(64,951)
Increase (decrease) in accounts payable	36,572	81,764	(17,960)
Increase (decrease) in other current liabilities	(7,433)	5,072	52,313
Net Cash Provided by Operating Activities	602,770	506,955	628,154
Cash Flows from Investing Activities:			
Capital expenditures	(527,386)	(595,739)	(738,706)
Investment in unconsolidated subsidiaries		(7,652)	(36,641)
Proceeds from sale of property, plant and equipment	81,084	20,363	1,434
Distribution from unconsolidated subsidiaries	1,500	5,500	
Aspect acquisition, net of cash acquired			(97,792)
Net Cash Used in Investing Activities	(444,802)	(577,528)	(871,705)
Cash Flows from Financing Activities:			
Exercise of stock options	24,685	7,692	12,283
Cash dividends paid	(9,755)	(9,147)	(9,042)
Proceeds from bank debt	135,435	158,669	675,000
Repayment of bank debt	(221,195)	(124,929)	(375,000)
Repayment of note payable obtained in Aspect acquisition	(3,580)	(19,507)	(9,605)
Repayment of treasury stock obligation	(36,626)		
Net Cash (Used in) Provided by Financing Activities	(111,036)	12,778	293,636
Increase (Decrease) in Cash and Cash Equivalents	46,932	(57,795)	50,085
Cash and Cash Equivalents at Beginning of Year	15,442	73,237	23,152
Cash and Cash Equivalents at End of Year	$ 62,374	$ 15,442	$ 73,237

Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 31,824	$ 31,303	$ 25,745
Income taxes paid (refunded)	$ 51,147	$ (40,394)	$ 66,131
Non-cash financing and investing activities:			
Treasury stock and note obligation	$ 36,626		
Issuance of treasury stock for acquisition			$ 14,238
Debt assumed in acquisition			$ 40,043

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND OTHER COMPREHENSIVE INCOME

NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands, except common stock)	Comprehensive Income (Loss)	Common Stock Shares Issued	Common Stock Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock At Cost	Total Shareholders' Equity
December 31, 2000		59,002,162	$196,672	$373,259	$325,452		$(45,701)	$ 849,682
Net Income	$ 133,575				133,575			133,575
Change in fair value of cash flow hedges, net of income tax	5,070					5,070		5,070
Treasury stock issued for acquisition				7,867			6,371	14,238
Exercise of stock options		509,161	1,697	14,978				16,675
Cash dividends ($.16 per share)					(9,042)			(9,042)
Total	$ 138,645							
December 31, 2001		59,511,323	$198,369	$396,104	$449,985	$5,070	$(39,330)	$ 1,010,198
Net Income	$ 17,652				17,652			17,652
Reclassification of unrealized gains on hedges to net income, net of $.5 income tax	1					1		1
Change in fair value of cash flow hedges, net of income tax	(19,769)					(19,769)		(19,769)
Change in additional minimum liability and other, net of tax	95					95		95
Exercise of stock options		356,744	1,189	9,167				10,356
Cash dividends ($.16 per share)					(9,147)			(9,147)
Total	$ (2,021)							
December 31, 2002		59,868,067	$199,558	$405,271	$458,490	$(14,603)	$(39,330)	$ 1,009,386
Net Income	$ 77,992				77,992			77,992
Change in fair value of cash flow hedges, net of income tax	2,324					2,324		2,324
Change in additional minimum liability and other, net of tax	1,393					1,393		1,393
Exercise of stock options		876,516	2,922	25,937				28,859
Cash dividends ($.17 per share)					(9,755)			(9,755)
Treasury stock purchase							(36,626)	(36,626)
Total	$ 81,709							
December 31, 2003		60,744,583	$202,480	$431,208	$526,727	$(10,886)	$(75,956)	$ 1,073,573

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in tables, unless otherwise indicated, are in thousands, except per share amounts)

Note 1 - Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

Accounting policies used by Noble Energy, Inc. and its subsidiaries conform to accounting principles generally accepted in the United States of America. The more significant of such policies are discussed below. The consolidated accounts include Noble Energy, Inc. (the "Company" or "Noble Energy") and the consolidated accounts of its wholly-owned subsidiaries. Effective December 31, 2001, Energy Development Corporation ("EDC"), a previously wholly-owned subsidiary of Samedan Oil Corporation ("Samedan"), was merged into Samedan, another previously wholly-owned subsidiary. Effective December 31, 2002, Samedan was merged into Noble Energy, Inc. Also effective December 31, 2002, Noble Trading, Inc. ("NTI") was merged into Noble Gas Marketing, Inc. ("NGM") under the new name of Noble Energy Marketing, Inc. ("NEMI"). All significant intercompany balances and transactions have been eliminated upon consolidation.

Nature of Operations

The Company is an independent energy company engaged, directly or through its subsidiaries or various arrangements with other companies, in the exploration, development, production and marketing of crude oil and natural gas. The Company has exploration, exploitation and production operations domestically and internationally. The domestic areas consist of: offshore in the Gulf of Mexico and California; the Gulf Coast Region (Louisiana and Texas); the Mid-Continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, Nevada, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel), the North Sea (Denmark, the Netherlands and the United Kingdom) and Vietnam. The Company also markets domestic crude oil and natural gas production through NEMI.

Use of Estimates

The preparation of the consolidated financial statements requires management of the Company to make a number of estimates and assumptions relating to the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The Company's estimates of crude oil and natural gas reserves are the most significant. All of the reserve data in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Noble Energy has engaged independent third-party reserve engineers to perform an audit of the Company's procedures and methods used to estimate proved reserves for each of the three years 2001-2003. The audit for 2003 included a review of the areas representing 80 percent of the Company's reserves. In addition, Noble Energy has obtained independent third-party estimates for several major international properties including those in Ecuador, Equatorial Guinea and Israel. Other items subject to estimates and assumptions include the carrying amount of property, plant and equipment; asset retirement obligations; valuation allowances for receivables and deferred income tax assets; environmental liabilities; valuation of derivative instruments; and assets and obligations related to employee benefits. Actual results could differ from those estimates.

The SEC requested clarification, which the Company provided, as to the Company's Israel and Equatorial Guinea gas reserves recorded in excess of existing contract amounts. SEC guidelines do not limit reserve bookings only to contracted volumes if it can be demonstrated that there is reasonable certainty that a market exists, which the Company believes exists in both of these situations. The Israel gas contract is for a period of 11 years. The Israel gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is twenty times greater than Noble

Energy's uncontracted net estimated proved reserves. In Equatorial Guinea, the gas contract, which runs through 2026, is between the field owners and the methanol plant owners. Noble Energy, through its subsidiaries, holds a working interest in the field as well as an interest in the methanol plant. The Company has recorded reserves through the end of the concession's term in 2040. Noble Energy has obtained independent third-party engineer reserve estimates for both of these projects.

Foreign Currency Translation

The U.S. dollar is considered the primary currency for each of the Company's international operations. Transactions that are completed in a foreign currency are translated into U.S. dollars and recorded in the financial statements. Translation gains or losses were not material in any of the periods presented and are included in other income on the statements of operations.

Materials and Supplies Inventories

Materials and supplies inventories, consisting principally of tubular goods and production equipment, are stated at the lower of cost or market, with cost being determined by the first-in, first-out method.

Property, Plant and Equipment

The Company accounts for its crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties are amortized to operations by the unit-of-production method based on proved developed crude oil and natural gas reserves on a property-by-property basis as estimated by Company engineers. The total asset retirement obligations of $199.3 million consist of $175.9 million for the United States and $23.4 million for the North Sea and are included in future production and development costs for purposes of estimating the future net revenues relating to the Company's proved reserves. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Individually significant unproved crude oil and natural gas properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized on a composite method based on the Company's experience of successful drilling and average holding period. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed. Repairs and maintenance are expensed as incurred.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the Company reviews oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or commodity prices. The Company estimates the future cash flows expected in connection with the properties and compares such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is written down to their fair value as determined by discounting its estimated future cash flows. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, and timing of future production, future capital expenditures and a discount rate commensurate with the risk-free interest rate reflective of the lives remaining for the respective oil and gas properties.

The Company recognized $31.9 million of impairments in 2003, primarily related to a reserve revision on the East Cameron 338 field in the Gulf of Mexico after recompletion and remediation activities produced less-than-expected results. An analysis of the performance response of the field resulted in a reduction in proved reserves of 2.2 MMBoe (unaudited).

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Capitalization of Interest

The Company capitalizes interest costs associated with the development and construction of significant properties or projects.

Statement of Cash Flows

For purposes of reporting cash flows, cash and cash equivalents include cash on hand and investments purchased with original maturities of three months or less.

Basic Earnings Per Share and Diluted Earnings Per Share

Basic earnings per share ("EPS") of common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of common stock includes the effect of outstanding stock options. The following table summarizes the calculation of basic EPS and diluted EPS components as of December 31:

	2003		*2002*		*2001*	
(in thousands except per share amounts)	*Income (Numerator)*	*Shares (Denominator)*	*Income (Numerator)*	*Shares (Denominator)*	*Income (Numerator)*	*Shares (Denominator)*
Net income/shares	$77,992	56,964	$17,652	57,196	$133,575	56,549
Basic EPS	$1.37		$.31		$2.36	
Net income/shares	$77,992	56,964	$17,652	57,196	$133,575	56,549
Effect of Dilutive Securities						
Stock options		575		567		754
Adjusted net income and shares	$77,992	57,539	$17,652	57,763	$133,575	57,303
Diluted EPS	$1.36		$.31		$2.33	

The table below reflects the amount of options not included in the EPS calculation above, as they were antidilutive.

	2003	*2002*	*2001*
Options excluded from dilution calculation	1,533,290	2,229,978	1,485,303
Range of exercise prices	$37.63 - $43.21	$35.40 - $43.21	$38.88 - $43.21
Weighted average exercise price	$41.10	$39.77	$41.29

Accounting for Employee Stock-Based Compensation

At December 31, 2003, the Company had two stock-based employee compensation plans, which are described more fully in "Note 5 - Common Stock, Stock Options and Stockholder Rights." The Company accounts for those plans under the intrinsic value recognition and measurement principles of Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. At issuance, no stock-based employee compensation cost was reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

(in thousands except per share amounts)	*2003*	*2002*	*2001*
Net income, as reported	$ 77,992	$ 17,652	$133,575
Add: Stock-based compensation cost recognized, net of related tax benefit	153	418	
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax benefit	(10,022)	(9,934)	(8,248)
Pro forma net income	$ 68,123	$ 8,136	$125,327
Earnings per share:			
Basic - as reported	$ 1.37	$ .31	$ 2.36
Basic - pro forma	$ 1.20	$ .14	$ 2.22
Diluted - as reported	$ 1.36	$ .31	$ 2.33
Diluted - pro forma	$ 1.18	$ .14	$ 2.19

Fair value estimates are based on several assumptions and should not be viewed as indicative of the operations of the Company in future periods. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2003, 2002 and 2001, respectively, as follows:

(amounts expressed in percentages)	*2003*	*2002*	*2001*
Interest rate	5.07	4.78	5.46
Dividend yield	.38	.43	.40
Expected volatility	28.38	40.26	38.19
Expected life (in years)	9.42	9.73	9.64

The weighted average fair value of options granted using the Black-Scholes option pricing model for 2003, 2002 and 2001, respectively, is as follows:

	2003	*2002*	*2001*
Black-Scholes model weighted average fair value option price	$16.64	$18.14	$23.86

Revenue Recognition and Gas Imbalances

The Company records revenues from the sales of crude oil, natural gas and methanol when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

When the Company has an interest with other producers in certain properties from which crude oil or natural gas is produced, the Company uses the entitlements method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount sold by the Company in excess of its entitlement is treated as a liability. Any amount sold by the Company less than its entitlement is treated as a receivable. The Company records the non-current portion of the liability in other deferred credits and non-current liabilities, and the current portion of the liability in other current liabilities. The Company records the non-current portion of the receivable in other assets and the current portion of the receivable in other current assets. The Company's natural gas imbalance liabilities were $17.0 million and $15.4 million at December 31, 2003 and 2002, respectively. The Company's imbalance receivables were $22.2 million and $20.1 million at December 31, 2003 and 2002, respectively, and are valued at the amount that is expected to be received.

Revenues derived from electricity generation are recognized when power is transmitted or delivered, the price is fixed and determinable and collectibility is reasonably assured.

NEMI records third-party sales, net of cost of goods sold, as GMP when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

Derivative Financial Instruments and Hedging Activities

The Company, from time to time, uses various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include fixed price hedges, variable to fixed price swaps, costless collars and other contractual arrangements. Although these derivative instruments expose the Company to credit risk, the Company monitors the creditworthiness of its counterparties and believes that losses from nonperformance are unlikely to occur. Hedging gains and losses related to the Company's crude oil and natural gas production are recorded in oil and gas sales and royalties.

The FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," in June 1998. The statement established accounting and reporting standards requiring every derivative instrument (including certain derivative instruments embedded in other contracts) to be recorded on 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 wherein gains and losses are reflected in shareholders' equity as AOCI until the hedged item is recognized. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item on the statements of operations, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

The Company adopted SFAS No. 133 effective January 1, 2001. The adoption of this statement did not have a material impact on the Company's results of operations or financial position, as of the date of adoption. At December 31, 2003, the Company recorded crude oil and natural gas hedge receivables and liabilities of $56.1 million and $67.6 million, respectively, and other comprehensive loss, net of tax, of $7.6 million related to the Company's derivative contracts.

Self-Insurance

The Company self-insures the medical and dental coverage provided to certain of its employees, certain workers' compensation and the first $250,000 of its general liability coverage.

Liabilities are accrued for self-insured claims when sufficient information is available to reasonably estimate the amount of the loss.

Unconsolidated Subsidiaries

Through its ownership in AMCCO, the Company owns a 45 percent interest in AMPCO, which completed construction of a methanol plant in Equatorial Guinea in the second quarter of 2001. During 1999, AMCCO issued $125 million Series A-2 senior secured notes due December 15, 2004 to fund construction payments owed in connection with the construction of its methanol plant. The Company's investment in the methanol plant is included in investment in unconsolidated subsidiaries. The $125 million Series A-2 notes are in current installments of long-term debt on the Company's balance sheet.

The plant construction started during 1998 and initial production of commercial grade methanol commenced May 2, 2001. The plant is designed to produce 2,500 MTpd of methanol, which equates to approximately 20,000 Bpd. At this level of production, the plant would purchase approximately 125 MMcfpd of natural gas from the 34 percent-owned Alba field. The methanol plant has a contract through 2026 to purchase natural gas from the Alba field. For more information, see "Note 9 - Unconsolidated Subsidiaries" of this Form 10-K.

Electricity Generation - Ecuador Integrated Power Project

The Company, through its subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., has a 100 percent ownership interest in an integrated gas-to-power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies fuel to the Machala power plant located in Machala, Ecuador. The revenues attributable to the gas-to-power project are reported in "Electricity Sales" and the expenses are reported as "Electricity Generation."

Cumulative Effect of Change in Accounting Principle

On January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," and recorded a non-cash charge of $9.0 million ($5.8 million, net of tax) as the cumulative effect of change in accounting principle.

Reclassification

Certain reclassifications have been made to the 2002 and 2001 consolidated financial statements to conform to the 2003 presentation. These reclassifications are not material to the Company's financial position.

Recently Issued Pronouncements

In December 2003, the SEC issued SAB No. 104, "Revenue Recognition." This SAB revises or rescinds portions of the revenue recognition interpretive guidance included in the SAB codification to make it consistent with current authoritative accounting guidance. The principal revisions relate to revenue recognition guidance no longer necessary due to developments in U.S. generally accepted accounting principles. The pronouncement had no impact on the Company's historical financial statements.

SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits - An Amendment of FASB Statements No. 87, 88 and 106," revises employers' disclosures about pension plans and other postretirement benefit plans and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. Most of the requirements are effective for financial statements with fiscal years ending after December 15, 2003. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 6 - Employee Benefit Plans" of this Form 10-K. The Company has made additional disclosures in its 2003 financial statements in compliance with SFAS No. 132.

SFAS No. 143, "Accounting for Asset Retirement Obligations," was issued in June 2001. This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. The Company's asset retirement obligations consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and gas properties. The Company adopted SFAS No. 143 on January 1, 2003 and, as of December 31, 2003, recorded as the fair value of asset retirement obligations, $109.4 million related to the United States and $15.1 million related to the North Sea. The Company recognized, as the cumulative effect of adoption of this standard, a non-cash pre-tax charge of $9.0 million in 2003. The expected future retirement obligation for the United States is $175.9 million and for the North Sea is $23.4 million. The difference between the expected future retirement obligation and the fair value of the retirement obligation will be expensed beginning in 2003 based on the credit-adjusted risk-free rate of 8.5 percent until the asset retirement date.

Below is a reconciliation of the beginning and ending aggregate carrying amount of the Company's asset retirement obligations:

(dollars in thousands)	*Twelve Months Ended December 31, 2003*
Beginning of the period	$
Initial adoption entry	109,821
Liabilities incurred in the current period	18,680
Liabilities settled in the current period	(13,295)
Accretion expense	9,331
End of the period	$ 124,537

The following table summarizes the pro forma net income and earnings per share, as of December 31, for each of the years, for the change in accounting had it been implemented on January 1, 2001 (in thousands, except per share amounts):

	2002		*2001*	
	As Reported	Pro Forma	As Reported	Pro Forma
Net income	$ 17,652	$ 8,556	$ 133,575	$ 124,770
Net income per share, basic	$ .31	$ .15	$ 2.36	$ 2.21
Net income per share, diluted	$ .31	$ .15	$ 2.33	$ 2.18

In addition, on a pro forma basis as required by SFAS No. 143, if the Company had applied the provisions of SFAS No. 143 as of January 1, 2001, the amount of asset retirement obligations would have been $99.7 million.

SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities that fall within the scope of SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, with certain exceptions, and for hedging relationships designated after June 30, 2003. The adoption of this statement had no impact on the Company's historical financial statements.

SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. During the second quarter of 2003, the Company adopted SFAS No. 150. As a result, the Company recorded an additional 1,044,454 shares of treasury stock at a cost of $36.6 million and an obligation of $36.6 million. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 12 - Company Stock Repurchase Forward Program" of this Form 10-K.

FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51," addresses consolidation by business enterprises of variable interest entities. This Interpretation requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. Special provisions apply to enterprises that have fully or partially applied Interpretation No. 46 prior to issuance of this revised Interpretation. Otherwise, application of this Interpretation is required in financial statements of public entities that have interests in variable interest entities or potential variable interest entities commonly referred to as special-purpose entities for periods ending after December 15, 2003. Application by public entities for all other types of entities is required in financial statements for periods ending after March 15, 2004. The provisions of this Interpretation would be applied if the Company were to acquire an interest in a variable interest entity. The adoption of this statement had no impact on the Company's historical financial statements.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("the Act") became law. The Act introduces a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. FASB Staff Position 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," allows deferral of the recognition of the Act's provisions until authoritative guidance on the accounting for the federal subsidy is issued. The Company has elected to defer recognition of the effects of the Act in the accounting for and disclosure of its postretirement benefit plan in accordance with the Staff Position. Authoritative guidance on accounting for the federal subsidy is pending. Final guidance could require the Company to change previously reported information. The Company does not believe that the effects of the Act will have a material impact on its financial condition or results of operations.

In June 2002, the EITF reached a consensus on certain issues contained in Topic 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts," under EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." While the Company does not engage in energy trading activities, the EITF has expanded its definition of energy trading activities to include the marketing activities in which the Company is engaged. The Company has reclassified its statements of operations for all periods to present its GMP activities on a net rather than a gross basis. The adoption of EITF 02-03 resulted in a decrease in revenues and a decrease in operating expenses of $649.6 million and $656.4 million for the years ended December 31, 2002 and 2001, respectively. The adoption of EITF 02-03 had no effect on operating income or cash flow.

Accounting for Costs Associated with Mineral Rights

During 2003, a reporting issue arose regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting crude oil and natural gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. The EITF has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how Noble Energy classifies these assets. Historically, the Company has included the costs of mineral rights associated with extracting crude oil and natural gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, net of amortization, the Company most likely would be required to reclassify certain amounts out of oil and gas properties and into a separate intangible assets line item. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules.

If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, Noble Energy would be required to reclassify the estimated amounts as follows:

	December 31,	
Intangible Assets (in thousands)	*2003*	*2002*
Proved leasehold acquisition costs	$ 835,738	$ 1,083,103
Unproved leasehold acquisition costs	127,194	153,789
Total leasehold acquisition costs	962,932	1,236,892
Less: accumulated depletion	(496,227)	(554,932)
Net leasehold acquisition costs	$ 466,705	$ 681,960

Further, the Company does not believe the classification of the costs of mineral rights associated with extracting crude oil and natural gas as intangible assets would have any impact on compliance with covenants under the Company's debt agreements.

Note 2 - Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between two willing parties.

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable

The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Crude Oil and Natural Gas Derivative Financial Instruments

The fair value of crude oil and natural gas derivative instruments is the estimated amount the Company would receive or pay to terminate the agreements at the reporting date taking into account creditworthiness of the counterparties.

Long-Term Debt

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for debt of the same remaining maturities.

The carrying amounts and estimated fair values of the Company's financial instruments, including current items, as of December 31, for each of the years are as follows:

	2003		2002	
(in thousands)	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Crude oil and natural gas price hedge agreements	$ (11,132)	$ (11,132)	$ (22,520)	$ (22,520)
Long-term debt	$ (776,021)	$ (836,271)	$ (977,116)	$ (991,086)

Note 3 - Debt

A summary of debt at December 31 follows:

(in thousands)	*2003*		*2002*	
	Debt	*Percentage Interest Rate*	*Debt*	*Percentage Interest Rate*
$400 million Credit Agreement, maturity date November 2006	$ 140,000	2.19	$ 380,000	2.47
$300 million Credit Agreement, maturity date October 2005	190,000	2.09		
Note obtained in Aspect acquisition, due May 2004	7,928	6.25	11,508	6.25
7 1/4% Notes Due 2023	100,000	7.25	100,000	7.25
8% Senior Notes Due 2027	250,000	8.00	250,000	8.00
7 1/4% Senior Debentures Due 2097	100,000	7.25	100,000	7.25
AMCCO Note, due December 2004	125,000	8.95	125,000	8.95
Israel Note, due 2004	20,746	2.16	58,738	2.18
Outstanding debt	933,674		1,025,246	
Less: unamortized discount	3,979		6,211	
current installment of long-term debt	153,674		41,919	
Long-term debt	$ 776,021		$ 977,116	

The Company's total long-term debt, net of unamortized discount, at December 31, 2003, was $776.0 million compared to $977.1 million at December 31, 2002. The ratio of debt-to-book capital (defined as the Company's total debt plus its equity) was 46 percent at December 31, 2003, compared with 50 percent at December 31, 2002.

The Company entered into a $400 million five-year credit agreement on November 30, 2001, with certain commercial lending institutions, which exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. The interest rate is based upon a Eurodollar rate plus a range of 60 to 145 basis points depending upon the percentage of utilization and credit rating. At December 31, 2003, there was $140 million borrowed against this credit agreement, which has a maturity date of November 30, 2006.

The Company entered into a new $300 million 364-day credit agreement on November 3, 2003 with certain commercial lending institutions, which exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. The interest rate is based upon a Eurodollar rate plus a range of 62.5 to 150 basis points depending upon the percentage of utilization and credit rating. At December 31, 2003, there was $190 million borrowed against this credit agreement. The agreement has a maturity date of October 28, 2004 for the revolving commitment and a final maturity date of October 28, 2005 for the term commitment that includes any balance remaining after the revolving commitment matures.

The current installment of long-term debt totals $153.7 million at December 31, 2003.

During 2004, a subsidiary of the Company borrowed a total of $150 million from certain commercial lending institutions. The interest rate on the borrowing is LIBOR plus an effective range of 60 to 130 basis points depending on credit rating and the borrowing is for a term of five years. Proceeds were used to reduce amounts due under the $400 million credit agreement.

Financial covenants on both the $400 million and $300 million credit facilities include the following: (a) the ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense ("EBITDAX") to interest expense for any consecutive period of four fiscal quarters ending on the last day of a fiscal quarter may not be less than 4.0 to 1.0;

(b) the total debt to capitalization ratio, expressed as a percentage, may not exceed 60 percent at any time; and (c) the total asset value of the Company's restricted entities may not be less than $800 million at any time.

Note 4 - Income Taxes

The following table details the difference between the federal statutory tax rate and the effective tax rate for the years ended December 31:

(amounts expressed in percentages)	*2003*	*2002*	*2001*
Statutory rate	35.0	35.0	35.0
Effect of:			
State taxes, net of federal benefit	.4	1.1	.3
Difference between U.S. and foreign rates	14.6	36.8	7.6
Write-off of Vietnam investment	(11.5)		
Other, net	(2.0)	(2.0)	.4
Effective rate	36.5	70.9	43.3

The net current deferred tax asset in the following table is classified as other current assets on the consolidated balance sheet. The tax effects of temporary differences that gave rise to deferred tax assets and liabilities as of December 31 were:

(in thousands)	*2003*	*2002*
U.S. and State Current Deferred Tax Assets:		
Accrued expenses	$ 1,507	$ 980
Deferred income	351	387
Allowance for doubtful accounts	2,184	353
Mark-to-market - derivative contracts	4,102	7,864
Net U.S. and State Current Deferred Tax Assets	8,144	9,584
U.S. and State Non-current Deferred Tax Assets (Liabilities):		
Property, plant and equipment, principally due to differences in depreciation, amortization, lease impairment and abandonments	(140,760)	(183,338)
Accrued expenses	4,777	4,777
Deferred income	2,848	4,594
Allowance for doubtful accounts	5,935	5,935
Foreign and state income tax accruals	8,716	11,940
Postretirement benefits	8,169	9,668
Other	(235)	(245)
Net U.S. and State Non-current Deferred Tax Assets (Liabilities)	(110,550)	(146,669)
Total Net U.S. and State Deferred Tax Assets (Liabilities)	(102,406)	(137,085)
Foreign Non-current Deferred Tax Assets (Liabilities):		
Property, plant and equipment of foreign operations	(54,809)	(55,270)
Foreign loss carryforward	16,732	21,148
Net Foreign Non-current Deferred Tax Assets (Liabilities)	(38,077)	(34,122)
Valuation allowance	(14,519)	(21,148)
Total Net Deferred Tax Assets (Liabilities)	$(155,002)	$(192,355)

The components of income (loss) from operations before income taxes as of December 31 for each year are as follows:

(in thousands)	*2003*	*2002*	*2001*
Domestic	$ 56,068	$ (11,636)	$ 166,999
Foreign	85,571	39,532	(16,869)
Total	$ 141,639	$ 27,896	$ 150,130

The income tax provision (benefit) relating to operations consists of the following for the years ended December 31:

(in thousands)	2003	2002	2001
U.S. current	$ 45,985	$ (7,945)	$ 24,743
U.S. deferred	(31,087)	1,421	53,591
State current	1,867	895	651
State deferred	(1,084)	(212)	360
Foreign current	32,341	14,675	6,200
Foreign deferred	461	16,113	5,490
Provision including discontinued operations	48,483	24,947	91,035
Income tax provision associated with discontinued operations	(3,264)	5,146	26,068
Total tax provision	$ 51,747	$ 19,801	$ 64,967

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2003. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

The Company has not recorded U.S. deferred income taxes on the undistributed earnings of its consolidated foreign subsidiaries since management intends to permanently reinvest those earnings. As of December 31, 2003, the undistributed earnings of the consolidated foreign subsidiaries were approximately $90.8 million. Upon distribution of these earnings in the form of dividends or otherwise, the Company may be subject to U.S. income taxes and foreign withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable on the eventual remittance of these earnings because of the possible application of U.S. foreign tax credits. Presently the Company is not claiming foreign tax credits, but it may be in a credit position when any future remittance of foreign earnings takes place.

The Company recognized deferred tax assets associated with its foreign loss carryforwards. The tax effect of these carryforwards decreased from $21.1 million in 2002 to $16.7 million in 2003. The valuation allowances associated with those carryforwards decreased from $21.1 million in 2002 to $14.5 million in 2003. This change was due to the elimination of the carryforward and offsetting valuation allowance associated with Vietnam, the elimination of the valuation allowance associated with Israel and the partial elimination of the valuation allowance associated with China. Because of the relatively short carryforward period in China and the lack of a long-term fixed price contract, the valuation allowance associated with China was not fully eliminated.

Note 5 - Common Stock, Stock Options and Stockholder Rights

The Company has two stock option plans, the 1992 Stock Option and Restricted Stock Plan ("1992 Plan") and the 1988 Non-Employee Director Stock Option Plan ("1988 Plan"). The Company accounts for these plans under APB Opinion No. 25.

Under the Company's 1992 Plan, the Board of Directors may grant stock options and award restricted stock. As of December 31, 2003, no restricted stock had been issued under the 1992 Plan. Since the adoption of the 1992 Plan, stock options have been issued at the market price on the date of grant. The earliest the granted options may be exercised is over a three-year period at the rate of 33 1/3 percent each year commencing on the first anniversary of the grant date. The options expire ten years from the grant date. The 1992 Plan was amended in 2000 and again in 2003, by a vote of the shareholders, to increase the maximum number of shares of common stock that may be issued under the 1992 Plan to 9,250,000 shares. At December 31, 2003, the Company had reserved 6,939,524 shares of common stock for issuance, including 3,218,265 shares available for grant, under its 1992 Plan.

The Company's 1988 Plan allows stock options to be issued to certain non-employee directors at the market price on the date of grant. The options may be exercised one year after issue and expire ten years from the grant date. The 1988 Plan provides for the grant of options to purchase a maximum of 550,000 shares of the Company's authorized but unissued common stock. The 1988 Plan was amended at the shareholders' annual meeting on April 24, 2001 to provide for the granting of a consistent number of stock options to each non-employee director annually (10,000 stock options for the first calendar year of service and 5,000 stock options for each year thereafter) and to change the annual grant date to February 1, commencing February 1, 2002. At December 31, 2003, the Company had reserved 297,571 shares of common stock for issuance, including 49,786 shares available for grant, under its 1988 Plan.

The Company adopted a stockholder rights plan on August 27, 1997, designed to assure that the Company's stockholders receive fair and equal treatment in the event of any proposed takeover of the Company and to guard against partial tender offers and other abusive takeover tactics to gain control of the Company without paying all stockholders a fair price. The rights plan was not adopted in response to any specific takeover proposal. Under the rights plan, the Company declared a dividend of one right ("Right") on each share of Noble Energy, Inc. common stock. Each Right will entitle the holder to purchase one one-hundredth of a share of a new Series A Junior Participating Preferred Stock, par value $1.00 per share, at an exercise price of $150.00. The Rights are not currently exercisable and will become exercisable only in the event a person or group acquires beneficial ownership of 15 percent or more of Noble Energy, Inc. common stock. The dividend distribution was made on September 8, 1997, to stockholders of record at the close of business on that date. The Rights will expire on September 8, 2007.

A summary of the status of Noble Energy's stock option plans as of December 31, 2001, 2002 and 2003, and changes during each of the years then ended, is presented below.

	Options Outstanding		Options Exercisable	
	Number Outstanding	Exercise Price	Number Exercisable	Weighted Average Exercise Price
Outstanding at December 31, 2000	**3,721,105**	**$ 29.44**	**2,408,522**	**$ 32.08**
Options granted	723,400	$ 42.77		
Options exercised	(509,161)	$ 24.97		
Options canceled	(81,267)	$ 33.11		
Outstanding at December 31, 2001	**3,854,077**	**$ 32.46**	**2,530,285**	**$ 32.10**
Options granted	732,500	$ 32.66		
Options exercised	(356,744)	$ 21.56		
Options canceled	(36,612)	$ 37.02		
Outstanding at December 31, 2002	**4,193,221**	**$ 33.38**	**2,871,943**	**$ 32.84**
Options granted	758,900	$ 35.42		
Options exercised	(876,516)	$ 28.16		
Options canceled	(106,561)	$ 36.96		
Outstanding at December 31, 2003	**3,969,044**	**$ 34.83**	**2,642,077**	**$ 34.40**

The following table summarizes information about Noble Energy's stock options which were outstanding, and those which were exercisable, as of December 31, 2003.

Options Outstanding				Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
\$17.79 - \$22.23	520,788	4.9 Years	\$20.06	520,788	\$20.06
\$22.23 - \$26.68	74,642	1.5 Years	\$24.39	74,642	\$24.39
\$26.68 - \$31.13	103,762	4.0 Years	\$28.91	103,762	\$28.91
\$31.13 - \$35.57	1,333,157	8.4 Years	\$34.06	243,744	\$32.89
\$35.57 - \$40.02	1,051,701	3.9 Years	\$38.14	1,011,701	\$38.21
\$40.02 - \$44.47	884,994	5.1 Years	\$42.32	687,440	\$42.10
	3,969,044	5.8 Years	\$34.83	2,642,077	\$34.40

Compensation expense totaling \$.2 million and \$.6 million was recognized in 2003 and 2002, respectively, due to the accelerated vesting of stock options as a result of the retirement of certain employees. There was no compensation expense recognized in 2001.

The Company claimed deductions on its 2002 and 2003 federal income tax returns for compensation expense associated with the exercise of stock options. This increased the Company's federal income tax refund by \$2.0 million for 2002 and decreased its liability by \$3.9 million and \$4.0 million for 2003 and 2001, respectively.

Note 6 - Employee Benefit Plans

Pension Plan and Other Postretirement Benefit Plans

The Company has a non-contributory defined benefit pension plan covering substantially all of its domestic employees. The benefits are based on an employee's years of service and average earnings for the 60 consecutive calendar months of highest compensation. The Company also has an unfunded restoration plan, which provides for restoration of amounts to which employees are entitled under the provisions of the pension plan, but which are subject to limitations imposed by federal tax laws. The Company's funding policy has been to make annual contributions equal to the actuarially computed liability to the extent such amounts are deductible for income tax purposes.

The Company sponsors other plans for the benefit of its employees and retirees. These plans include health care and life insurance benefits. The Company uses a December 31 measurement date for its plans. The following table reflects the required disclosures on the Company's pension and other postretirement benefit plans at December 31:

	Pension Benefits		*Other Benefits*	
(in thousands)	*2003*	*2002*	*2003*	*2002*
Change in benefit obligation				
Benefit obligation at beginning of year	$106,224	$ 89,587	$ 6,141	$ 2,688
Service cost	5,271	4,986	534	346
Interest cost	6,772	7,071	524	314
Amendments	196	380		
Plan participants' contributions			114	90
Actuarial loss	4,366	8,439	2,053	2,849
Benefits paid	(4,559)	(4,239)	(210)	(146)
Benefit obligation at year-end	$118,270	$106,224	$ 9,156	$ 6,141
Change in plan assets				
Fair value of plan assets at beginning of year	$ 56,660	$ 53,570	$	$
Actual return on plan assets	7,583	(3,471)		
Employer contribution	14,341	10,800	210	146
Benefits paid	(4,559)	(4,239)	(210)	(146)
Fair value of plan assets at end of year	$ 74,025	$ 56,660	$	$
Funded status	$(44,245)	$(49,564)	$ (9,156)	$ (6,141)
Unrecognized net actuarial loss	25,849	23,366	4,955	2,472
Unrecognized prior service cost (benefit)	2,402	2,525	(836)	(244)
Unrecognized net transition obligation	1,142	1,167		
Accrued benefit costs	$(14,852)	$(22,506)	$ (5,037)	$ (3,913)
Components of net periodic benefit cost				
Service cost	$ 5,271	$ 4,986	$ 534	$ 346
Interest cost	6,772	7,071	524	314
Expected return on plan assets	(5,857)	(5,474)		
Transition obligation recognition	24	24		
Amortization of prior service cost	319	306	(110)	(30)
Recognized net actuarial loss	158	845	272	73
Net periodic benefit cost	$ 6,687	$ 7,758	$ 1,220	$ 703
Additional Information				
Increase in minimum liability included in accumulated other comprehensive income	$ 1,594	$ 94	$	$
Weighted-average assumptions used to determine benefit obligations at December 31,				
Discount rate	6.25%	6.75%	6.25%	6.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Weighted-average assumptions used to determine net periodic benefit costs for year ended December 31,				
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected long-term return on plan assets	8.50%	8.50%		
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

Amounts recognized in the statement of financial position consist of:

(in thousands)	Pension Benefits 2003	Pension Benefits 2002	Other Benefits 2003	Other Benefits 2002
Accrued benefit cost	$ 14,852	$ 22,506	$	$
Intangible assets	3,974	2,297		
Accumulated other comprehensive income, net of tax	1,036	61		
Net amount recognized	$ 19,862	$ 24,864	$	$

In selecting the assumption for expected long-term rate of return on assets, Noble Energy considers the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the trusts' asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. The Company assumes its long-term asset mix will be consistent with its target asset allocation of 70 percent equity and 30 percent fixed income, with a range of plus or minus 10 percent acceptable degree of variation in the plan's asset allocation. Based on these factors, the Company expects its pension assets will earn an average of 8.5 percent per annum over the life of the plan. This basis is consistent with the prior year.

The following table reflects the aggregate pension obligation components for the defined benefit pension plan and the restoration benefit plan, which are aggregated in the previous tables, at December 31:

(in thousands)	Defined Benefit Pension Plan 2003	Defined Benefit Pension Plan 2002	Restoration Benefit Plan 2003	Restoration Benefit Plan 2002
Aggregated pension benefits				
Aggregate fair value of plan assets	$ 74,025	$ 56,660	$	$
Aggregate accumulated benefit obligation	80,738	68,476	13,708	13,081
Funded status of net periodic benefit obligation	$ (6,713)	$(11,816)	$(13,708)	$(13,081)

Medical trend rates were 10 percent for 2003, grading down to five percent in years 2008 and later. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following results:

(in thousands)	1-Percentage-Point increase	1-Percentage-Point decrease
Total service and interest cost components	$ 1,207	$ 930
Total postretirement benefit obligation	$10,296	$ 8,166

The following table reflects weighted-average asset allocations by asset category for the Company's pension benefit plans at December 31:

	Target Allocation 2004	Plan Assets 2003	Plan Assets 2002
Asset category			
Equity securities	60% - 80%	70.75%	63.54%
Fixed income	20% - 40%	28.97%	29.57%
Other	0% - 0%	0.28%	6.89%
Total	0% - 0%	100.00%	100.00%

The investment policy for the defined benefit pension plan is determined by the Company's employee benefits committee ("the committee") with input from a third-party investment consultant. Based on a review of historical rates of return achieved by equity and fixed income investments in various combinations over multi-year holding periods and an evaluation of the probabilities of achieving acceptable real rates of return, the committee has determined the target asset allocation deemed most appropriate to meet the immediate and future benefit payment requirements for the plan and to provide a diversification strategy which reduces market and interest rate risk. A one percent decrease in the expected return on plan assets would have resulted in an increase in benefit expense of $.7 million in 2003.

Noble Energy bases its determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2003, the Company had cumulative asset losses of approximately $7.0 million, which remain to be recognized in the calculation of the market-related value of assets.

Plan assets include $52.4 million of equity securities and $21.6 million of fixed income securities. The Company contributed cash of $14.3 million to its pension plans during 2003.

Contributions

The Company expects to make cash contributions of $2.0 million to pension plans during 2004 (unaudited). The decrease in expected contribution for 2004 is due primarily to the higher actual return on pension plan assets experienced during 2003 and an expectation of a continued positive return on plan assets during 2004 due to the recovery of market conditions.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	*Pension Benefits*	*Other Benefits*
2004	$ 4,900	$
2005	$ 5,000	$
2006	$ 5,200	$
2007	$ 5,300	$
2008	$ 5,400	$
Years 2009 to 2013	$ 28,600	$

Employee Savings Plan ("ESP")

The Company has an ESP that is a defined contribution plan. Participation in the ESP is voluntary and all regular employees of the Company are eligible to participate. The Company may match up to 100 percent of the participant's contribution not to exceed six percent of the employee's base compensation. The following table indicates the Company's contribution for the years ended December 31:

(in thousands)	*2003*	*2002*	*2001*
Employers' plan contribution	$2,412	$2,302	$2,145

Note 7 - Additional Balance Sheet and Statement of Operations Information

Included in accounts receivable-trade is an allowance for doubtful accounts at December 31:

(in thousands)	*2003*	*2002*
Allowance for doubtful accounts	$ 6,255	$ 1,510

Other current assets included the following at December 31:

(in thousands)	*2003*	*2002*
Deferred tax asset	$ 8,144	$ 9,584

Other current liabilities included the following at December 31:

(in thousands)	*2003*	*2002*
Gas imbalance liabilities	$ 5,113	$ 1,090
Accrued interest payable	$ 11,324	$ 11,178
Workers compensation	$ 1,200	$ 1,200

Crude oil and natural gas operations expense, from continuing operations, included the following for the years ended December 31:

(in thousands)	*Consolidated*	*United States*	*North Sea*	*Israel(2)*	*Equatorial Guinea*	*Other Int'l*
2003						
Lease operating (1)	$ 120,060	$ 75,356	$ 10,662	$	$ 16,319	$ 17,723
Production taxes	19,473	14,601				4,872
Workover expense	6,303	6,303				
Total operations expense	$ 145,836	$ 96,260	$ 10,662	$	$ 16,319	$ 22,595
2002						
Lease operating (1)	$ 82,168	$ 61,217	$ 10,817	$	$ 9,848	$ 286
Production taxes	14,315	12,284				2,031
Workover expense	8,875	8,880	(5)			
Total operations expense	$ 105,358	$ 82,381	$ 10,812	$	$ 9,848	$ 2,317
2001						
Lease operating (1)	$ 79,733	$ 63,169	$ 6,075	$	$ 6,775	$ 3,714
Production taxes	8,829	8,686				143
Workover expense	15,094	15,094				
Total operations expense	$ 103,656	$ 86,949	$ 6,075	$	$ 6,775	$ 3,857

(1) Lease operating expense includes labor, fuel, repairs, replacements, saltwater disposal, ad valorem taxes and other related lifting costs.

(2) Production did not begin until 2004.

Crude oil and natural gas exploration expense included the following for the years ended December 31:

(in thousands)		*United*	*North*		*Equatorial*	*Other*
2003	*Consolidated*	*States*	*Sea*	*Israel*	*Guinea*	*Int'l*
Dry hole expense	$ 63,637	$ 32,408	$ 4,023	$ 6,711	$	$ 20,495
Unproved lease amortization	33,381	25,296	1,264	900		5,921
Seismic	17,674	15,903	1,662		51	58
Staff expense	30,182	17,483	3,105	214	83	9,297
Other	3,944	3,601	449			(106)
Total exploration expense	$ 148,818	$ 94,691	$ 10,503	$ 7,825	$ 134	$ 35,665
2002						
Dry hole expense	$ 81,396	$ 64,449	$ 544	$	$	$ 16,403
Unproved lease amortization	21,254	19,426	178	900		750
Seismic	20,492	14,282	827	1,671	1,341	2,371
Staff expense	24,928	20,081	2,833	54		1,960
Other	2,631	2,457	828			(654)
Total exploration expense	$ 150,701	$ 120,695	$ 5,210	$ 2,625	$ 1,341	$ 20,830
2001						
Dry hole expense	$ 99,684	$ 54,810	$ 28,992	$	$	$ 15,882
Unproved lease amortization	17,213	15,112	1,725	375		1
Seismic	15,607	13,328	2,209	5	39	26
Staff expense	17,148	14,431	1,605			1,112
Other	2,444	2,811	419			(786)
Total exploration expense	$ 152,096	$ 100,492	$ 34,950	$ 380	$ 39	$ 16,235

During the past three years, there was no third-party purchaser that accounted for more than 10 percent of the annual total crude oil and natural gas sales and royalties.

Note 8 - Derivatives Instruments and Hedging Activities

Cash Flow Hedges – The Company, from time to time, uses various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include fixed price hedges, variable to fixed price swaps, costless collars and other contractual arrangements. Although these derivative instruments expose the Company to credit risk, the Company takes reasonable steps to protect itself from nonperformance by its counterparties including periodic assessment of necessary provisions for bad debt allowance; however, the Company is not able to predict sudden changes in its counterparties' creditworthiness. The Company accounts for its derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and has elected to designate its derivative instruments as cash flow hedges. Derivative instruments designated as cash flow hedges are reflected at fair value on the Company's consolidated balance sheets. Changes in fair value, to the extent the hedge is effective, are reported in AOCI until the forecasted transaction occurs. Gains and losses from such derivative instruments related to the Company's crude oil and natural gas production and which qualify for hedge accounting treatment are recorded in oil and gas sales and royalties on the Company's consolidated statements of operations upon sale of the associated products. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative's fair value. Any ineffective portion of the derivative instrument's change in fair value is recognized immediately in other income.

During 2003, 2002 and 2001, the Company entered into various crude oil and natural gas fixed price swaps, costless collars and costless collar combinations related to its crude oil and natural gas production. The tables below depict the various transactions.

Natural Gas	*2003*	*2002*	*2001*
Hedge MMBTUpd	190,038	170,274	16,947
Fixed price range			\$5.23 - \$5.41
Floor price range	\$3.25 - \$3.80	\$2.00 - \$3.50	\$3.25 - \$5.00
Ceiling price range	\$4.00 - \$5.25	\$2.45 - \$5.10	\$4.60 - \$6.25
Percent of daily production	56%	50%	5%

Crude Oil	*2003*	*2002*	*2001*
Hedge Bpd	15,793	5,247	126
Fixed price			\$27.81
Floor price range	\$23.00 - \$27.00	\$23.00 - \$24.00	
Ceiling price range	\$27.20 - \$35.05	\$29.30 - \$30.10	
Percent of daily production	44%	18%	.5%

During 2003, 2002 and 2001, the Company included a reduction of \$67.5 million and gains of \$5.9 million and \$5.1 million, respectively, related to its cash flow hedges in oil and gas sales and royalties. During 2003, 2002 and 2001, no gains or losses were reclassified into earnings as a result of the discontinuance of hedge accounting treatment. During 2003, the Company recorded \$.5 million of ineffectiveness related to its cash flow hedges. No ineffectiveness was recorded for 2002 and 2001.

In 2001, the Company only had financial derivatives in the fourth quarter. Of these fourth quarter derivatives, 25,000 MMBTU of natural gas per day was terminated early. Amounts in AOCI were reclassified into earnings in the same periods during which the hedged forecasted transaction affected earnings, resulting in an increase in oil and gas sales and royalties of \$6.3 million during the fourth quarter of 2001. As a result, the Company recognized an additional \$.70 per MMBTU on the 25,000 MMBTU of natural gas per day in 2001.

As of December 31, 2003, the Company had entered into costless collars related to its natural gas and crude oil production to support the Company's investment program as follows:

	Natural Gas		Crude Oil	
Production Period	MMBTUpd	Price Per MMBTU Floor - Ceiling	Bopd	Price Per Bbl Floor - Ceiling
1Q 2004	120,000	\$4.81 - \$7.77	15,000	\$25.33 - \$31.53
2Q 2004	120,000	\$4.06 - \$5.95	15,000	\$24.83 - \$31.22
3Q 2004	120,000	\$4.19 - \$5.99	15,000	\$25.00 - \$31.13
4Q 2004	120,000	\$4.19 - \$6.42	5,000	\$24.00 - \$30.00

The contracts entitle the Company (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the last scheduled NYMEX trading day applicable for each calculation period is less than the floor price. The Company would pay the counterparty if the settlement price for the last scheduled NYMEX trading day applicable for each calculation period is more than the ceiling price. The amount payable by the floating price payor, if the floating price is above the ceiling price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the ceiling price in respect of each calculation period. The amount payable by the fixed price payor, if the floating price is below the floor price, is the product of the notional quantity per calculation period and the excess, if any, of the floor price over the floating price in respect of each calculation period.

Accumulated Other Comprehensive Income (Loss) – As of December 31, 2003 and 2002, the balance in AOCI included net deferred losses of $7.6 million and $14.6 million, respectively, related to the fair value of crude oil and natural gas derivative instruments accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefit of $4.1 million and $7.9 million, respectively.

If commodity prices were to stay the same as they were at December 31, 2003, approximately $11.2 million of crude oil and natural gas derivative instruments would be recorded in earnings during the next twelve months as the forecasted transactions occur, and would be recorded as a reduction in oil and gas sales and royalties. Any actual increase or decrease in revenues will depend upon market conditions over the period during which the forecasted transactions occur. All forecasted transactions currently being hedged with crude oil and natural gas derivative instruments designated as cash flow hedges are expected to occur by December 2004.

Other Derivative Financial Instruments – In addition to the derivative instruments pertaining to the Company's production as described above, NEMI, from time to time, employs various derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to natural gas price risk. Most of the purchases made by NEMI are on an index basis; however, purchasers in the markets in which NEMI sells often require fixed or NYMEX-related pricing. NEMI may use a derivative to convert the fixed or NYMEX sale to an index basis thereby determining the margin and minimizing the risk of price volatility.

NEMI records gains and losses on derivative instruments using mark-to-market accounting. 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. NEMI recorded a loss of $.2 million, a gain of $.9 million and a loss of $.5 million in GMP proceeds during 2003, 2002 and 2001, respectively, related to derivative instruments.

Receivables/Payables Related to Crude Oil and Natural Gas Derivative Financial Instruments – At December 31, 2003, the Company's consolidated balance sheet included a receivable of $56.1 million and a payable of $67.6 million related to crude oil and natural gas derivative financial instruments. At December 31, 2002, the Company's consolidated balance sheet included a receivable of $10.3 million and a payable of $32.3 million related to crude oil and natural gas derivative financial instruments.

During 2003, the Company had contracts with Enron North America Corporation ("ENA") that resulted in gains of $6.9 million (net of allowance) included in GMP proceeds. In addition, as of December 31, 2003, the Company had NYMEX-related transactions with ENA totaling 149 contracts with a mark-to-market receivable value of $1.8 million. For additional discussion of ENA matters, see "Note 10 - Commitments and Contingencies" of this Form 10-K.

Interest Rate Lock – The Company occasionally enters into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCI, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At December 31, 2003, the Company's consolidated balance sheet included a payable of $4.0 million related to an outstanding interest rate lock. The amount of deferred loss included in AOCI at December 31, 2003 was $2.6 million, net of tax.

Note 9 - Unconsolidated Subsidiaries

Through its ownership in AMCCO, the Company owns a 45 percent interest in AMPCO, which completed construction of a methanol plant in Equatorial Guinea in the second quarter of 2001. During 1999, AMCCO issued $125 million Series A-2 senior secured notes due December 15, 2004 to fund construction payments owed in connection with the construction of its methanol plant. The Company's investment in the methanol plant is included in investment in unconsolidated subsidiaries. The $125 million Series A-2 notes are in current installments of long-term debt on the Company's balance sheet.

The plant construction started during 1998 and initial production of commercial grade methanol commenced May 2, 2001. The plant is designed to produce 2,500 MTpd of methanol, which equates to approximately 20,000 Bpd. At this level of production, the plant would purchase approximately 125 MMcfpd of natural gas from the 34 percent-owned Alba field. The methanol plant has a contract through 2026 to purchase natural gas from the Alba field.

AMCCO, AMPCO, AMPCO Marketing LLC, AMPCO Services LLC and Samedan Methanol are accounted for using the equity method.

The following are the summarized balance sheets at December 31 and the statements of operations for the years ended December 31 for subsidiaries accounted for using the equity method:

Consolidated Balance Sheets (Unaudited)
Equity Method Subsidiaries

(in thousands)	*2003*	*2002*
Assets		
Current assets	$ 73,604	$ 74,832
Non-current assets - net of depreciation	397,084	412,134
Total Assets	$ 470,688	$ 486,966
Liabilities, Minority Interest and Members' Equity		
Current liabilities	$ 39,855	$ 37,419
Members' equity	430,833	449,547
Total Liabilities, Minority Interest and Members' Equity	$ 470,688	$ 486,966

Consolidated Statements of Operations (Unaudited)
Equity Method Subsidiaries

(in thousands)	*2003*	*2002*	*2001*
Revenue			
Methanol sales	$ 171,126	$ 97,476	$ 43,343
Other income	17,232	18,471	5,346
Total Revenue	$ 188,358	$ 115,947	$ 48,689
Less cost of goods sold	76,244	71,687	28,548
Gross Margin	$ 112,114	$ 44,260	$ 20,141
Expenses			
DD&A	$ 20,018	$ 20,763	$ 8,427
Other expenses	5		4,363
Interest (net of amount capitalized)			7,013
Loss on early extinguishment of debt (1)			24,776
Administrative	3,686	3,076	317
Total Expenses	$ 23,709	$ 23,839	$ 44,896
Net Income (Loss)	$ 88,405	$ 20,421	$ (24,755)

(1) During 2001, the Company's partner called its Series A-1 Secured Notes. A prepayment penalty associated with this early extinguishment was fully allocated to the partner and the Company did not recognize any portion of this loss in its financial statements.

Note 10 - Commitments and Contingencies

The Company and its subsidiaries are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters and does not believe that the ultimate disposition of such proceedings will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

On October 15, 2002, Noble Gas Marketing, Inc. and Samedan Oil Corporation, collectively referred to as the "Noble Defendants," filed proofs of claim in the United States Bankruptcy Court for the Southern District of New York in response to bankruptcy filings by Enron Corporation and certain of its subsidiaries and affiliates, including Enron North America Corporation ("ENA"), under Chapter 11 of the U.S. Bankruptcy Code. The proofs of claim relate to certain natural gas sales agreements and aggregate approximately $12 million.

On December 13, 2002, ENA filed a complaint in which it objected to the Noble Defendants' proofs of claim, sought recovery of approximately $60 million from the Noble Defendants under the natural gas sales agreements, sought declaratory relief in respect of the offset rights of the Noble Defendants and sought to invalidate the arbitration provisions contained in certain of the agreements in issue. The Noble Defendants intend to vigorously defend against ENA's claims and do not believe that the ultimate disposition of the bankruptcy proceeding will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

On January 13, 2003, the Noble Defendants filed an answer to ENA's complaint. On January 29, 2003, the Noble Defendants filed the Motion of Noble Energy Marketing, Inc., as Successor to Noble Gas Marketing, Inc., and Noble Energy, Inc., as Successor to Samedan Oil Corporation, to Compel Arbitration. On March 4, 2003, the Court issued its Order Governing Mediation of Trading Cases and Appointing the Honorable Allan L. Gropper as Mediator (the "Mediation Order") which, among other things, abated this case and referred it to mediation along with other pending adversary proceedings in the Enron bankruptcy cases which involve disputes arising from or in connection with commodity trading contracts. Pursuant to the Mediation Order, the Honorable Allan L. Gropper (United States Bankruptcy Judge for the Southern District of New York) is acting as mediator for this case and the other trading cases which have been referred to him. The mediation for this case was held on December 17, 2003 and no resolution was reached.

Note 11 - Geographical Data

The Company has operations throughout the world and manages its operations by country. The following information is grouped into five components that are all primarily in the business of natural gas and crude oil exploration and production: United States, North Sea, Israel, Equatorial Guinea, and Other International, Corporate and Marketing. Other International includes operations in Argentina, China, Ecuador and Vietnam. During 2002, the Company changed the composition of its reportable components due to changes in the significance of its international business. This was due to the completion of international development projects in China, Ecuador, Equatorial Guinea and the North Sea. Amounts in the 2001 financial statements were reclassified to conform to the 2002 composition of reportable components.

Year Ended December 31, 2003
(Dollars in Thousands)

	Consolidated	United States	North Sea	Israel	Equatorial Guinea	Other Int'l, Corporate & Marketing
REVENUES						
Oil Sales	$ 364,382	$ 153,891	$ 81,019	$	$ 65,016	$ 64,456
Gas Sales	474,762	451,476	19,539		3,628	119
Gathering, Marketing and Processing	68,158					68,158
Electricity Sales	58,022					58,022
Income from Unconsolidated Subsidiaries	40,626				40,626	
Other	5,036	919	1,105	127		2,885
Total Revenues	1,010,986	606,286	101,663	127	109,270	193,640
COSTS AND EXPENSES						
Oil and Gas Operations	145,836	96,260	10,662		16,319	22,595
Transportation	14,679		9,024			5,655
Oil and Gas Exploration	148,818	94,691	10,503	7,825	134	35,665
Gathering, Marketing and Processing	59,114					59,114
Electricity Generation	50,846					50,846
DD&A	309,343	254,041	28,219	40	6,115	20,928
Impairment of Operating Assets	31,937	31,937				
SG&A	52,466	15,884		5	603	35,974
Accretion of Asset Retirement Obligation	9,331	8,449	882			
Interest Expense (net)	46,977					46,977
Total Costs and Expenses	869,347	501,262	59,290	7,870	23,171	277,754
OPERATING INCOME (LOSS) FROM CONTINUING OPERATIONS	141,639	105,024	42,373	(7,743)	86,099	(84,114)
DISCONTINUED OPERATIONS	(9,325)	(9,325)				
CUMULATIVE EFFECT OF SFAS 143	(8,983)	(8,983)				
INCOME (LOSS) BEFORE TAXES	$ 123,331	$ 86,716	$ 42,373	$ (7,743)	$ 86,099	$ (84,114)
LONG-LIVED ASSETS (PRIMARILY PROPERTY, PLANT AND EQUIPMENT, NET)	$ 2,099,741	$ 977,583	$ 77,293	$ 253,482	$ 370,430	$ 420,953
TOTAL ASSETS	$ 2,842,649	$ 1,037,106	$ 163,381	$ 267,915	$ 620,663	$ 753,584

Year Ended December 31, 2002
(Dollars in Thousands)

	Consolidated	United States	North Sea	Israel	Equatorial Guinea	Other Int'l, Corporate & Marketing
REVENUES						
Oil Sales	$ 257,435	$ 112,010	$ 72,041	$	$ 45,830	$ 27,554
Gas Sales	351,591	331,935	19,497		3,052	(2,893)
Gathering, Marketing and Processing	64,517					64,517
Electricity Sales	18,257					18,257
Income from Unconsolidated Subsidiaries	9,532				9,532	
Other	1,246	100	389	(8)		765
Total Revenues	702,578	444,045	91,927	(8)	58,414	108,200
COSTS AND EXPENSES						
Oil and Gas Operations	105,358	82,381	10,812		9,848	2,317
Transportation	16,441		9,618			6,823
Oil and Gas Exploration	150,701	120,695	5,210	2,625	1,341	20,830
Gathering, Marketing and Processing	53,982					53,982
Electricity Generation	15,946					15,946
DD&A	236,881	192,708	28,279	31	5,849	10,014
SG&A	47,664	27,768	630	10	2,045	17,211
Interest Expense (net)	47,709					47,709
Total Costs and Expenses	674,682	423,552	54,549	2,666	19,083	174,832
OPERATING INCOME (LOSS) FROM CONTINUING OPERATIONS	27,896	20,493	37,378	(2,674)	39,331	(66,632)
DISCONTINUED OPERATIONS	14,703	14,703				
INCOME (LOSS) BEFORE TAXES	$ 42,599	$ 35,196	$ 37,378	$ (2,674)	$ 39,331	$ (66,632)
LONG-LIVED ASSETS (PRIMARILY PROPERTY, PLANT AND EQUIPMENT, NET)	$ 2,139,785	$ 1,225,501	$ 89,316	$ 180,267	$ 154,231	$ 490,470
TOTAL ASSETS	$ 2,730,015	$ 1,337,017	$ 109,868	$ 187,429	$ 406,131	$ 689,570

Year Ended December 31, 2001
(Dollars in Thousands)

	Consolidated	United States	North Sea	Israel	Equatorial Guinea	Other Int'l, Corporate & Marketing
REVENUES						
Oil Sales	$ 214,083	$ 108,464	$ 39,972	$	$ 38,841	$ 26,806
Gas Sales	502,856	479,435	22,850		2,201	(1,630)
Gathering, Marketing and Processing	64,640					64,640
Electricity Sales						
Income from Unconsolidated Subsidiaries	6,981				6,981	
Other	953	(267)	1,299		183	(262)
Total Revenues	789,513	587,632	64,121		48,206	89,554
COSTS AND EXPENSES						
Oil and Gas Operations	103,656	86,949	6,075		6,775	3,857
Transportation	16,012		8,772			7,240
Oil and Gas Exploration	152,096	100,492	34,950	380	39	16,235
Gathering, Marketing and Processing	51,932					51,932
Electricity Generation						
DD&A	233,516	202,732	16,537	23	3,889	10,335
SG&A	44,164	26,554	2,699	3	917	13,991
Interest Expense (net)	38,007					38,007
Total Costs and Expenses	639,383	416,727	69,033	406	11,620	141,597
OPERATING INCOME (LOSS) FROM CONTINUING OPERATIONS	150,130	170,905	(4,912)	(406)	36,586	(52,043)
DISCONTINUED OPERATIONS	74,480	74,480				
INCOME (LOSS) BEFORE TAXES	$ 224,610	$ 245,385	$ (4,912)	$ (406)	$ 36,586	$ (52,043)
LONG-LIVED ASSETS (PRIMARILY PROPERTY, PLANT AND EQUIPMENT, NET)	$ 1,953,211	$ 1,308,504	$ 103,781	$ 101,407	$ 87,461	$ 352,058
TOTAL ASSETS	$ 2,479,848	$ 1,412,649	$ 114,563	$ 107,407	$ 220,231	$ 624,998

Note 12 - Company Stock Repurchase Forward Program

The Company's Board of Directors, in February 2000, authorized a repurchase of up to $50 million in the Company's common stock. On September 17, 2001 the Company's Board of Directors approved an expansion of the original repurchase program from $50 million to $100 million. During the fourth quarter of 2001, in conjunction with the expanded repurchase program, the Board approved a stock repurchase forward program. Under the stock repurchase forward program, one of the Company's banks purchased approximately $35 million of the Company's stock or 1,044,454 shares on the open market during the first quarter of 2002.

As of June 10, 2003, the Company and the bank amended the agreement to delete the provisions that allowed the Company to net settle the contract.

The program was scheduled to mature in January 2003 but was extended to January 2004. Under the provisions of the agreement with the bank, the Company could choose to purchase the shares from the bank, issue additional shares to the bank to the extent that the share price had decreased, pay the bank a net amount of cash to the extent that the share price had decreased, or receive from the bank a net amount of cash to the extent that the share price had increased. The bank had the right to terminate the agreement prior to the maturity date if the Company's share price decreased by 50 percent (to $16.77 per share) or if the Company's credit rating was downgraded below BBB- (S&P) or Baa3 (Moody's). If either event occurred and the bank exercised its right to terminate, the Company still retained the right to settle in cash or additional shares. The agreement limited the number of shares to be issued by the Company to 14,000,000 additional shares. Amounts paid or received related to the change in share price would be an addition or reduction to the Company's capital in excess of par value. As of December 31, 2002, the fair value of the Company's obligation under the contract was an obligation to pay approximately $36.1 million to the bank (and hold the shares as treasury stock), or the bank would return 81,946 shares of Company stock to the Company, or the bank would pay $3.1 million to the Company.

During the second quarter of 2003, the Company adopted SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." As a result, the Company recorded an additional 1,044,454 shares of treasury stock at a cost of $36.6 million and an obligation of $36.6 million. In December 2003, the Company paid the obligation in full.

Note 13 - Discontinued Operations

Pursuant to SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which replaced APB Opinion No. 30 for the disposal of segments of a business, the Company's consolidated financial statements have been reclassified for all periods presented to reflect the operations and assets of the properties being sold as discontinued operations. The net income from discontinued operations was classified on the consolidated statements of operations as "Discontinued Operations, Net of Tax."

During 2003, the Company identified five domestic property packages for disposition. Bids have now been received on all five packages. During 2003, property sales closed on four of the five packages, with the remaining property package expected to close during the first half of 2004. Total pretax proceeds on all five packages, before closing adjustments, are expected to be in excess of $110.0 million.

The Company recorded a loss, net of tax, related to discontinued operations of $6.1 million in 2003. Included in the discontinued operations loss was a $59.2 million ($38.5 million, net of tax) non-cash write down to market value for certain of the five property packages. The Company has reclassified the results of operations associated with the five property packages for 2001 and 2002 to discontinued operations. This reclassification did not have an effect on net income as previously reported for 2001 and 2002. As a result of the reclassification, oil and gas sales and royalties are lower, as well as the associated oil and gas operations and DD&A expense.

Summarized results of discontinued operations are as follows:

(dollars in thousands)	2003	2002	2001
	Year ended December 31,		
Revenues:			
Oil and gas sales and royalties	$ 106,339	$ 91,576	$ 154,873
Costs and Expenses:			
Write down to market value and realized loss	59,171		
Oil and gas operations	27,731	28,468	29,893
Depreciation, depletion and amortization	28,762	48,405	50,500
	115,664	76,873	80,393
Income (Loss) Before Income Taxes	(9,325)	14,703	74,480
Income Tax Provision (Benefit)	(3,264)	5,146	26,068
Income (Loss) From Discontinued Operations	$ (6,061)	$ 9,557	$ 48,412

The long-term debt of the Company is recorded at the consolidated level and is not reflected by each component. Thus, the Company has not allocated interest expense to the discontinued operations.

Supplemental Oil and Gas Information

(Unaudited)

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured, and estimates of engineers other than Noble Energy's might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Noble Energy has engaged independent third-party reserve engineers to perform an audit of the Company's procedures and methods used to estimate proved reserves for each of the three years 2001 - 2003. The audit for 2003 included a review of the areas representing 80 percent of the Company's reserves. In addition, Noble Energy has obtained independent third-party estimates for several major international properties including those in Ecuador, Equatorial Guinea and Israel. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. China, Ecuador and Equatorial Guinea are subject to production sharing contracts.

The SEC requested clarification, which the Company provided, as to the Company's Israel and Equatorial Guinea gas reserves recorded in excess of existing contract amounts. SEC guidelines do not limit reserve bookings only to contracted volumes if it can be demonstrated that there is reasonable certainty that a market exists, which the Company believes exists in both of these situations. The Israel gas contract is for a period of 11 years. The Israel gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is twenty times greater than Noble Energy's uncontracted net estimated proved reserves. In Equatorial Guinea, the gas contract, which runs through 2026, is between the field owners and the methanol plant owners. Noble Energy, through its subsidiaries, holds a working interest in the field as well as an interest in the methanol plant. The Company has recorded reserves through the end of the concession's term in 2040. Noble Energy has obtained independent third-party engineer reserve estimates for both of these projects.

The following definitions apply to the Company's categories of proved reserves:

Proved Reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Proved Developed Reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Undeveloped Reserves. Proved undeveloped oil and gas 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 recompletion.

For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to the SEC Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Proved Gas Reserves (Unaudited)

The following reserve schedule was developed by the Company's reserve engineers and sets forth the changes in estimated quantities of proved gas reserves of the Company during each of the three years presented.

	Natural Gas and Casinghead Gas (MMcf)(1)						
Proved reserves as of:	*United States*	*Argentina*	*Ecuador*	*Equatorial Guinea (2)*	*Israel (2)*	*North Sea*	*Total*
January 1, 2003	621,716	3,887	84,993	425,420	450,307	14,478	**1,600,801**
Revisions of previous estimates	3,070	(1,147)	2,147	182		4,392	**8,644**
Extensions, discoveries and other additions	44,463			126,962			**171,425**
Production	(106,609)	(292)	(7,842)	(14,566)		(5,059)	**(134,368)**
Sale of minerals in place	(10,406)						**(10,406)**
Purchase of minerals in place	5,824						**5,824**
December 31, 2003	558,058	2,448	79,298	537,998	450,307	13,811	**1,641,920**
Proved reserves as of:							
January 1, 2002	751,283	4,348	87,500	438,214	378,001	20,661	**1,680,007**
Revisions of previous estimates	(37,566)	(37)	281	(245)		18	**(37,549)**
Extensions, discoveries and other additions	42,806				72,306		**115,112**
Production	(119,664)	(424)	(2,788)	(12,549)		(6,201)	**(141,626)**
Sale of minerals in place	(20,290)						**(20,290)**
Purchase of minerals in place	5,147						**5,147**
December 31, 2002	621,716	3,887	84,993	425,420	450,307	14,478	**1,600,801**
Proved reserves as of:							
January 1, 2001	752,387	4,544	87,500	383,292	218,154	28,752	**1,474,629**
Revisions of previous estimates	(46,886)	36		(2,550)	159,847	(1,583)	**108,864**
Extensions, discoveries and other additions	129,172	371		66,410			**195,953**
Production	(134,507)	(603)		(8,938)		(6,508)	**(150,556)**
Sale of minerals in place	(246)						**(246)**
Purchase of minerals in place	51,363						**51,363**
December 31, 2001	751,283	4,348	87,500	438,214	378,001	20,661	**1,680,007**
Proved developed gas reserves as of:							
January 1, 2004	506,457	2,197	25,130	462,474	378,001	13,811	**1,388,070**
January 1, 2003	576,378	3,664	34,436	425,420		14,478	**1,054,376**
January 1, 2002	721,926	3,996		438,214		20,661	**1,184,797**
January 1, 2001	690,301	4,544		383,292		25,652	**1,103,789**

(1) The Company's international proved reserves do not differ materially from the volumes that would be calculated under the economic interest method.

(2) Includes reserves in excess of volumes under gas sales contracts.

Proved Oil Reserves (Unaudited)

The following reserve schedule was developed by the Company's reserve engineers and sets forth the changes in estimated quantities of proved oil reserves of the Company during each of the three years presented.

	Crude Oil and Condensate (Bbls in thousands)(1)					
Proved reserves as of:	*United States*	*Argentina*	*China*	*Equatorial Guinea*	*North Sea*	*Total*
January 1, 2003	62,023	9,283	10,930	111,019	8,223	**201,478**
Revisions of previous estimates	1,216	(91)	609	(333)	3,654	**5,055**
Extensions, discoveries and other additions	1,949	768		4,840		**7,557**
Production	(7,402)	(1,039)	(1,203)	(2,328)	(2,705)	**(14,677)**
Sale of minerals in place	(15,482)				(712)	**(16,194)**
Purchase of minerals in place						
December 31, 2003	42,304	8,921	10,336	113,198	8,460	**183,219**
Proved reserves as of:						
January 1, 2002	71,672	10,277	9,768	79,790	11,114	**182,621**
Revisions of previous estimates	(5,331)	36		(34)	(27)	**(5,356)**
Extensions, discoveries and other additions	2,929		1,162	33,182		**37,273**
Production	(6,652)	(1,030)		(1,919)	(2,864)	**(12,465)**
Sale of minerals in place	(732)					**(732)**
Purchase of minerals in place	137					**137**
December 31, 2002	62,023	9,283	10,930	111,019	8,223	**201,478**
Proved reserves as of:						
January 1, 2001	69,700	9,437	9,768	47,446	12,418	**148,769**
Revisions of previous estimates	324	(6)		(272)	407	**453**
Extensions, discoveries and other additions	7,453	1,846		34,303		**43,602**
Production	(7,363)	(1,000)		(1,687)	(1,711)	**(11,761)**
Sale of minerals in place	(37)					**(37)**
Purchase of minerals in place	1,595					**1,595**
December 31, 2001	71,672	10,277	9,768	79,790	11,114	**182,621**
Proved developed oil reserves as of:						
January 1, 2004	34,246	8,004	10,336	113,198	8,460	**174,244**
January 1, 2003	52,847	8,331	10,930	78,746	8,223	**159,077**
January 1, 2002	64,534	8,866		61,897	11,114	**146,411**
January 1, 2001	58,903	9,437		47,446	5,728	**121,514**

(1) The Company's international proved reserves do not differ materially from the volumes that would be calculated under the economic interest method.

Oil and Gas Operations (Unaudited)

Aggregate results of continuing operations for each period ended December 31, in connection with the Company's crude oil and natural gas producing activities, are shown below.

(in thousands)

December 31, 2003	*United States*	*Equatorial Guinea*	*Israel*	*North Sea*	*Other Int'l*	***Total***
Revenues	$ 605,367	$ 68,644	$	$ 100,558	$ 64,575	**$ 839,144**
Production costs	112,725	16,319		10,662	18,538	**158,244**
Transportation				9,024	5,655	**14,679**
E&P corporate	15,884	603	5		1,866	**18,358**
Exploration expenses	71,802	134	6,925	9,239	28,011	**116,111**
DD&A and valuation provision	278,426	6,101	910	29,405	23,795	**338,637**
Impairment of operating assets	31,937					**31,937**
Accretion expense	8,449			882		**9,331**
Income (loss)	86,144	45,487	(7,840)	41,346	(13,290)	**151,847**
Income tax expense (benefit)	17,795	21,770	(4,121)	19,586	9,479	**64,509**
Result of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 68,349	$ 23,717	$ (3,719)	$ 21,760	$ (22,769)	**$ 87,338**

December 31, 2002						
Revenues	$ 444,121	$ 45,830	$	$ 91,538	$ 27,537	**$ 609,026**
Production costs	86,342	6,795		10,813	5,180	**109,130**
Transportation				9,618	6,823	**16,441**
E&P corporate	27,768	2,045	10	630	1,090	**31,543**
Exploration expenses	102,323	1,341	1,725	5,032	20,733	**131,154**
DD&A and valuation provision	209,905	5,835	909	28,350	9,606	**254,605**
Income (loss)	17,783	29,814	(2,644)	37,095	(15,895)	**66,153**
Income tax expense	6,559	13,825		16,360	666	**37,410**
Result of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 11,224	$ 15,989	$ (2,644)	$ 20,735	$ (16,561)	**$ 28,743**

December 31, 2001						
Revenues	$ 588,036	$ 38,841	$	$ 62,823	$ 27,239	**$ 716,939**
Production costs	90,943	4,464		6,075	5,746	**107,228**
Transportation				8,772	7,240	**16,012**
E&P corporate	25,418	917	3	2,699	1,929	**30,966**
Exploration expenses	86,619	39	5	33,224	17,021	**136,908**
DD&A and valuation provision	216,305	3,830	382	18,171	8,679	**247,367**
Income (loss)	168,751	29,591	(390)	(6,118)	(13,376)	**178,458**
Income tax expense (benefit)	59,232	14,429		(2,721)	(700)	**70,240**
Result of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 109,519	$ 15,162	$ (390)	$ (3,397)	$ (12,676)	**$ 108,218**

Costs Incurred in Oil and Gas Activities (Unaudited)

Costs incurred in connection with the Company's crude oil and natural gas acquisition, exploration and development activities for each of the years are shown below.

(in thousands) December 31, 2003	*United States*	*Equatorial Guinea*	*Israel*	*North Sea*	*Other Int'l*	*Total*
Property acquisition costs						
Proved	$ 1,419	$	$	$ (125)	$	**$ 1,294**
Unproved	10,184				50	**10,234**
Total	$ 11,603	$	$	$ (125)	$ 50	**$ 11,528**
Exploration costs	$ 127,450	$ 134	$ 6,925	$ 10,086	$ 8,828	**$ 153,423**
Development costs	$ 98,717	$ 222,315	$ 66,751	$ 6,747	$ 7,249	**$ 401,779**
Asset retirement obligation	$ 12,566	$	$	$ 6,114	$	**$ 18,680**
December 31, 2002						
Property acquisition costs						
Proved	$ 7,873	$	$	$ 115	$	**$ 7,988**
Unproved	28,023			(238)	2,730	**30,515**
Total	$ 35,896	$	$	$ (123)	$ 2,730	**$ 38,503**
Exploration costs	$ 153,437	$ 1,351	$ 1,725	$ 5,062	$ 20,935	**$ 182,510**
Development costs	$ 131,244	$ 51,839	$ 14,767	$ 9,892	$ 60,934	**$ 268,676**
December 31, 2001						
Property acquisition costs						
Proved	$ 91,251	$	$	$ 6,318	$	**$ 97,569**
Unproved	76,808			2,167	2,310	**81,285**
Total	$ 168,059	$	$	$ 8,485	$ 2,310	**$ 178,854**
Exploration costs	$ 134,247	$ 4,003	$ 131	$ 34,766	$ 19,233	**$ 192,380**
Development costs	$ 279,297	$ 10,364	$ 11,163	$ 17,338	$ 75,910	**$ 394,072**

Development costs include $274.6 million, $245.6 million and $191.1 million spent to develop proved undeveloped reserves in 2003, 2002 and 2001, respectively.

Aggregate Capitalized Costs (Unaudited)

Aggregate capitalized costs relating to the Company's crude oil and natural gas producing activities, including asset retirement costs and related accumulated DD&A, as of December 31 are shown below:

	2003			*2002*		
(in thousands)	*U. S.*	*Int'l*	***Total***	*U. S.*	*Int'l*	***Total***
Unproved oil and gas properties	$ 155,426	$ 10,519	**$ 165,945**	$ 138,319	$ 16,532	**$ 154,851**
Proved oil and gas properties	2,302,002	818,102	**3,120,104**	3,053,256	1,069,914	**4,123,170**
	2,457,428	828,621	**3,286,049**	3,191,575	1,086,446	**4,278,021**
Accumulated DD&A	(1,508,381)	(252,650)	**(1,761,031)**	(1,972,282)	(189,540)	**(2,161,822)**
Net capitalized costs	$ 949,047	$ 575,971	**$ 1,525,018**	$ 1,219,293	$ 896,906	**$ 2,116,199**

Amounts at December 31, 2003 include an asset retirement cost of $82.2 million for the U.S. and $14.3 million for International.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves
(Unaudited)

The following information is based on the Company's best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2003, 2002 and 2001 in accordance with SFAS No. 69. The Standard requires the use of a 10 percent discount rate. This information is not the fair market value nor does it represent the expected present value of future cash flows of the Company's proved oil and gas reserves.

December 31, 2003	*United States*	*Ecuador*	*Equatorial Guinea*	*Israel*	*North Sea*	*Other Int'l*	***Total***
(in millions of dollars)							
Future cash inflows	$ 4,425	$ 317	$ 3,391	$1,177	$ 316	$ 582	**$ 10,208**
Future production costs	986	46	635	139	113	248	**2,167**
Future development costs	339	49	199	84	25	19	**715**
Future income tax expenses	1,033	86	1,224	311	78	94	**2,826**
Future net cash flows	2,067	136	1,333	643	100	221	**4,500**
10% annual discount for estimated timing of cash flows	833	50	760	292	11	76	**2,022**
Standardized measure of discounted future net cash flows	$ 1,234	$ 86	$ 573	$ 351	$ 89	$ 145	**$ 2,478**
December 31, 2002							
(in millions of dollars)							
Future cash inflows	$ 4,743	$ 268	$ 3,111	$1,181	$ 294	$ 648	**$ 10,245**
Future production costs	1,119	42	445	201	98	216	**2,121**
Future development costs	387	31	216	100	12	22	**768**
Future income tax expenses	985	33	860	263	68	111	**2,320**
Future net cash flows	2,252	162	1,590	617	116	299	**5,036**
10% annual discount for estimated timing of cash flows	877	59	953	301	21	93	**2,304**
Standardized measure of discounted future net cash flows	$ 1,375	$ 103	$ 637	$ 316	$ 95	$ 206	**$ 2,732**
December 31, 2001							
(in millions of dollars)							
Future cash inflows	$ 3,399	$ 264	$ 1,576	$ 900	$ 281	$ 317	**$ 6,737**
Future production costs	1,239	46	267	47	68	124	**1,791**
Future development costs	379	57	114	103	16	44	**713**
Future income tax expenses	437	26	598	193	49	24	**1,327**
Future net cash flows	1,344	135	597	557	148	125	**2,906**
10% annual discount for estimated timing of cash flows	562	56	406	364	25	65	**1,478**
Standardized measure of discounted future net cash flows	$ 782	$ 79	$ 191	$ 193	$ 123	$ 60	**$ 1,428**

The future net cash inflows for 2003, 2002 and 2001 do not include cash flows relating to the Company's anticipated future methanol or power sales.

Future cash inflows are computed by applying year-end prices, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of the Company's derivative financial instruments. See the following table for average prices per region:

December 31, 2003	*United States*	*Ecuador*	*Equatorial Guinea*	*Israel*	*North Sea*	*Other Int'l*	***Total***
Average oil price per Bbl	$ 30.16	$	$ 28.76	$	$ 30.64	$ 30.16	**$ 29.32**
Average gas price per Mcf	$ 5.64	$ 4.00	$ .25	$ 2.61	$ 4.15	$ .38	**$ 2.95**
December 31, 2002							
Average oil price per Bbl	$ 29.19	$	$ 27.10	$	$ 28.88	$ 32.00	**$ 28.31**
Average gas price per Mcf	$ 4.72	$ 3.15	$ .24	$ 2.62	$ 3.89	$ .30	**$ 2.84**
December 31, 2001							
Average oil price per Bbl	$ 16.43	$	$ 18.38	$	$ 19.24	$ 15.58	**$ 17.35**
Average gas price per Mcf	$ 2.96	$ 3.02	$ .25	$ 2.38	$ 3.27	$ .97	**$ 2.12**

The Company estimates that a $1.00 per Bbl change or a $.10 per Mcf change in the average crude oil price or the average natural gas price, respectively, from the year-end price would change the discounted future net cash flows before income taxes by approximately $96.8 million or $52.7 million, respectively.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the Company's proved crude oil and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions. Future development costs include $51.9 million, $62.2 million and $31.5 million that the Company expects to spend in 2004, 2005 and 2006, respectively, to develop proved undeveloped reserves.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to the Company's proved crude oil and natural gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax credits and allowances, but do not reflect the impact of general and administrative costs and exploration expenses of ongoing operations relating to the Company's proved crude oil and natural gas reserves.

At December 31, 2003, the Company estimated natural gas imbalance receivables of $22.2 million and estimated natural gas imbalance liabilities of $17.0 million; at year-end 2002, $20.1 million in receivables and $15.4 million in liabilities; and at year-end 2001, $20.9 million in receivables and $15.5 million in liabilities. Neither the natural gas imbalance receivables nor natural gas imbalance liabilities have been included in the standardized measure of discounted future net cash flows as of each of the three years ended December 31, 2003, 2002 and 2001.

Sources of Changes in Discounted Future Net Cash Flows (Unaudited)

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves, as required by SFAS No. 69, at year-end are shown below.

(in millions)	*2003*	*2002*	*2001*
Standardized measure of discounted future net cash flows at the beginning of the year	$ 2,732	$ 1,428	$ 4,074
Extensions, discoveries and improved recovery, less related costs	247	486	448
Revisions of previous quantity estimates	115	(158)	114
Changes in estimated future development costs	(148)	(243)	(128)
Purchases (sales) of minerals in place	(115)	(13)	108
Net changes in prices and production costs	(312)	1,636	(3,376)
Accretion of discount	405	208	564
Sales of oil and gas produced, net of production costs	(793)	(553)	(713)
Development costs incurred during the period	243	254	220
Net change in income taxes	(250)	(667)	908
Change in timing of estimated future production, and other	354	354	(791)
Standardized measure of discounted future net cash flows at the end of the year	$ 2,478	$ 2,732	$ 1,428

Supplemental Quarterly Financial Information

(Unaudited)

Supplemental quarterly financial information for the years ended December 31, 2003 and 2002 is as follows:

	Quarter Ended			
(in thousands except per share amounts)	*Mar. 31,*	*June 30,*	*Sept. 30,*	*Dec. 31,*
2003				
Revenues	$ 266,723	$ 247,167	$ 244,344	$ 252,752
Income (loss) from continuing operations before taxes	$ 58,236	$ 39,630	$ 48,239	$ (4,466)
Income (loss) from continuing operations	$ 32,712	$ 25,809	$ 31,567	$ (196)
Cumulative effect of change in accounting principle, net of tax	$ (5,839)	$	$	$
Discontinued operations, net of tax	$ 7,984	$ 3,260	$ 3,549	$ (20,854)
Net income (loss)	$ 34,857	$ 29,069	$ 35,116	$ (21,050)
Basic earnings (loss) per share:				
Income from continuing operations	$ 0.57	$ 0.45	$ 0.56	$ 0.00
Cumulative effect of change in accounting principle, net of tax	$ (0.10)	$	$	$
Discontinued operations, net of tax	$ 0.14	$ 0.06	$ 0.06	$ (0.37)
Net income (loss)	$ 0.61	$ 0.51	$ 0.62	$ (0.37)
Diluted earnings (loss) per share:				
Income from continuing operations	$ 0.56	$ 0.45	$ 0.55	$ 0.00
Cumulative effect of change in accounting principle, net of tax	$ (0.10)	$	$	$
Discontinued operations, net of tax	$ 0.14	$ 0.06	$ 0.07	$ (0.37)
Net income (loss)	$ 0.60	$ 0.51	$ 0.62	$ (0.37)
2002				
Revenues	$ 143,843	$ 167,160	$ 180,381	$ 211,194
Income (loss) from continuing operations before taxes	$ (18,136)	$ 22,874	$ (7,518)	$ 30,676
Income (loss) from continuing operations	$ (13,174)	$ 13,179	$ (4,171)	$ 12,261
Discontinued operations, net of tax	$ (1,924)	$ 3,940	$ 2,981	$ 4,560
Net income (loss)	$ (15,098)	$ 17,119	$ (1,190)	$ 16,821
Basic earnings (loss) per share:				
Income (loss) from continuing operations	$ (0.23)	$ 0.23	$ (0.07)	$ 0.21
Discontinued operations, net of tax	$ (0.03)	$ 0.07	$ 0.05	$ 0.08
Net income (loss)	$ (0.26)	$ 0.30	$ (0.02)	$ 0.29
Diluted earnings (loss) per share:				
Income (loss) from continuing operations	$ (0.23)	$ 0.23	$ (0.07)	$ 0.21
Discontinued operations, net of tax	$ (0.03)	$ 0.07	$ 0.05	$ 0.08
Net income (loss)	$ (0.26)	$ 0.30	$ (0.02)	$ 0.29

The first quarter of 2003 includes a loss from cumulative effect of change in accounting principle, net of tax of $5.8 million ($.10 per share) due to the adoption of SFAS No. 143. The fourth quarter of 2003 includes impairment of operating assets of $31.9 million ($20.7 million, net of tax). Amounts for 2002 have been reclassified to reflect the adoption of EITF 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts," as of

January 1, 2003. The adoption of EITF 02-03 resulted in a decrease in revenues and a decrease in operating expenses of $649.6 million for the year ended December 31, 2002. The adoption of EITF 02-03 had no effect on operating income or cash flow. In addition, amounts for 2002 have been reclassified to reflect the reporting of discontinued operations.

Independent Auditors' Report on
Consolidated Financial Statement Schedule

To the Shareholders and Board of Directors of Noble Energy, Inc.:

Under date of February 26, 2004, we reported on the consolidated balance sheets of Noble Energy, Inc. as of December 31, 2003 and 2002, and the related consolidated statements of operations, shareholders' equity and other comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003. In connection with our audits of the aforementioned consolidated financial statements, we also audited the related consolidated financial statement schedule. The consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statement schedule based on our audits.

In our opinion, the consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

Houston, Texas
February 26, 2004

Schedule II

NOBLE ENERGY, INC.

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2003, 2002 and 2001
(in thousands)

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2003					
Allowance for doubtful accounts (1)	1,510	4,745			6,255
Deferred tax asset valuation allowance (2)	21,148			6,629	14,519
2002					
Allowance for doubtful accounts	638	872			1,510
Deferred tax asset valuation allowance	17,115		4,033		21,148
2001					
Allowance for doubtful accounts	645			7	638
Deferred tax asset valuation allowance			17,115		17,115

(1) The increase in the allowance for doubtful accounts is related to financial derivative contracts with one of the Company's counterparties.

(2) The decrease in the valuation allowance associated with foreign loss carryforwards was due to the elimination of the carryforward and offsetting valuation allowance associated with Vietnam, the elimination of the valuation allowance associated with Israel and the partial elimination of the valuation allowance associated with China.

Atlantic Methanol Production Company, LLC

Financial Statements

For the Years Ended December 31, 2003, 2002 and 2001

Report of Independent Auditors

The Members
Atlantic Methanol Production Company, LLC

We have audited the accompanying balance sheet of Atlantic Methanol Production Company, LLC as of December 31, 2003 and 2002, and the related statements of operations, members' equity and cash flows for the years then ended. 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 Atlantic Methanol Production Company, LLC 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.

The accompanying financial statements for 2001 were not audited by us and, accordingly, we do not express an opinion on them.

Ernst & Young LLP

January 28, 2004
Fort Worth, Texas

Atlantic Methanol Production Company, LLC

Balance Sheet

(dollars in thousands)	*December 31,* 2003	2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 10,970	$ 12,091
Receivables - affiliates	10,029	7,460
Accounts receivable - trade	6,177	13,552
Other receivables	228	
Inventories	12,054	11,057
Deferred methanol cost *(Note 2)*	3,296	5,560
Deferred expenses *(Note 2)*	1,574	
Prepaid expenses and deposits	5,025	2,876
Total current assets	49,353	52,596
Property, Plant and Equipment:		
Plant, net of accumulated depreciation ($47,328 at December 31, 2003 and $29,299 at December 31, 2002)	373,564	388,003
Total Assets	$ 422,917	$ 440,599
LIABILITIES AND MEMBERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 527	$ 4,945
Accounts payable - affiliates	231	444
Accrued liabilities	11,419	4,290
Income and other taxes payable	633	
Deferred revenue *(Note 2)*	15,346	16,095
Distributions payable		2,530
Total current liabilities	28,156	28,304
Commitments and Contingencies *(Notes 3, 5 and 6)*		
Members' Equity	394,761	412,295
Total Liabilities and Members' Equity	$ 422,917	$ 440,599

See accompanying notes.

Atlantic Methanol Production Company, LLC

Statement of Operations

(dollars in thousands)	December 31, 2003	2002	2001
			(Unaudited)
Revenue:			
Methanol sales	$ 171,127	$ 97,476	$ 48,159
Shipping revenue *(Note 9)*	2,306	1,954	4,263
Sales of purchased third-party methanol *(Note 7)*	341	11,384	1,842
Other	11,829	1,800	594
Total Revenue	185,603	112,614	54,858
Costs and Expenses:			
Cost of methanol	$ 27,550	$ 21,824	$ 8,790
Shipping	19,011	17,709	15,304
Marketing	5,189	2,833	1,102
Cost of third-party purchased methanol sold *(Note 7)*	428	15,312	2,526
Net bridge cost recovery loss *(Note 7)*	318	2,134	8,427
Depreciation	19,197	18,791	9,364
General and administrative expense	22,664	15,675	6,524
Net profit interest *(Note 8)*	5,201		
Ship charter expense *(Note 9)*	1,079		
Total Costs and Expenses	100,637	94,278	52,037
Net Income	$ 84,966	$ 18,336	$ 2,821

See accompanying notes.

Atlantic Methanol Production Company, LLC

Statement of Members' Equity

(dollars in thousands)	*December 31,* 2003	2002	2001
			(Unaudited)
Members' equity, beginning of year:	$ 412,295	$ 413,919	$ 365,558
Contributions		15,340	46,540
Net income	84,966	18,336	2,821
Distributions declared to members	(102,500)	(35,300)	(1,000)
Members' equity, end of year	$ 394,761	$ 412,295	$ 413,919

See accompanying notes.

Atlantic Methanol Production Company, LLC

Statement of Cash Flows

(dollars in thousands)	*December 31,* 2003	2002	2001
			(Unaudited)
Cash Flows from Operating Activities			
Net income	$ 84,966	$ 18,336	$ 2,821
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	19,197	18,791	9,364
(Increase) decrease in receivables - affiliates	(2,569)	(3,189)	2,244
(Increase) decrease in receivables - trade	7,374	(11,837)	(1,715)
Increase in receivables - others	(228)		
Increase in prepaid expenses and deposits	(2,148)	(197)	(2,679)
(Increase) decrease inventories	(996)	7,760	(18,817)
(Increase) decrease in deferred methanol cost	2,263	(5,560)	
Increase in deferred expenses	(1,574)		
Increase (decrease) in accounts payable	(3,786)	3,078	1,704
Increase (decrease) in accounts payable - affiliates	(214)	(3,434)	3,878
Increase (decrease) in accrued liabilities	7,131	(3,047)	7,337
Increase (decrease) in deferred revenue	(749)	16,095	
Net cash provided by operating activities	$ 108,667	$ 36,796	$ 4,137
Cash Flows from Investing Activities			
Capital expenditures	$ (4,758)	$ (13,318)	$ (46,130)
Cash Flows from Financing Activities			
Capital contributions		15,340	46,540
Distribution of dividends to members	(105,030)	(33,770)	
Net cash used in financing activities	$ (105,030)	$ (18,430)	$ 46,540
Net increase (decrease) in cash and cash equivalents	(1,121)	5,048	4,547
Cash and cash equivalents, beginning of year	12,091	7,043	2,496
Cash and cash equivalents, end of year	$ 10,970	$ 12,091	$ 7,043

See accompanying notes.

1. Formation and Nature of Business

Atlantic Methanol Production Company, LLC (the Company) was formed to construct, operate and own a methanol production facility (the Plant) and related facilities on Bioko Island, Equatorial Guinea. The Company is 90% owned by Atlantic Methanol Associates, LLC (AMA) and 10% owned by Guinea Equatorial Oil and Gas Marketing Ltd. (GEOGM). AMA is owned 50% by Marathon E.G. Methanol Limited, which is ultimately a wholly owned subsidiary of Marathon Oil Corporation (Marathon) and 50% owned by Samedan Methanol, which is an indirect subsidiary of Noble Energy, Inc. (Noble).

Production of methanol began in May 2001. The Plant utilizes natural gas supplied by the nearby Alba Field under a 25-year fixed-price contract of $0.25 per MMBtu. Subsidiaries of Marathon and Noble own 63.3% and 33.7%, respectively, of the Alba Field.

Prior to January 3, 2002 subsidiaries of CMS Energy Corporation (CMS) owned a portion of the Company, the Alba field, AMPCO Marketing LLC (Note 3), and AMPCO Services LLC (Note 3) now controlled by Marathon and its subsidiaries. The assets of the Company are recorded at historical cost.

2. Summary of Significant Accounting Policies

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Inventories

Inventories consist of methanol held in tanks and spare parts for the Plant and are stated at the lower of cost or market, with cost being determined by the weighted average cost method.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Depreciation is provided on a straight-line basis over the assets estimated useful lives, and in the case of the Plant, over a 25-year life.

The Company reviews the carrying value of property, plant and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, a write-down is recognized equal to an amount by which the carrying value exceeds the estimated future discounted cash flows. No impairments were recorded in 2003.

Deferred Revenue and Deferred Methanol Cost

Under the Company's sales agreements with Solvadis Chemag (MG) (Note 6) and AMPCO Marketing, LLC (Marketing) (Note 3) (collectively the Marketers), risk of physical loss to the methanol transfers when it is loaded on a tanker and leaves port in Equatorial Guinea. At this point, the Marketers are invoiced a provisional amount for the methanol and are required to pay 30 days subsequent to arrival of the methanol in the U.S. or Europe. Since final pricing is not known until the Marketers' resell the product under their third-party contracts, revenue and the related cost of methanol is deferred until the Marketers resell the methanol to third parties. At December 31, 2003, there were approximately 49,967 and 30,905 metric tons of methanol held by Marketing and MG, respectively, that had not been sold to third parties. Revenue from provisional billings of approximately $15.4 million associated with these volumes is reflected as deferred revenue on the accompanying balance sheet. Cost of methanol related to these volumes of approximately $3.3 million is reflected as deferred methanol cost on the accompanying balance sheet.

Deferred Expenses

Deferred expenses are shipping costs that have been incurred but are associated with methanol that is included in deferred revenue. These costs are expensed as the associated methanol in deferred revenue is sold.

Foreign Currency Translation

The U.S. dollar is considered the functional currency of the Company. Transactions that are completed in a foreign currency are translated into U.S. dollars and recorded in the financial statements. Some costs and revenues are invoiced in Euros, British Pound Sterling and the Communaute Financiere Africaine Franc (XAF). These costs and revenues are translated to US dollars on a monthly basis based upon the exchange rate on the last day of the current month.

Use of Estimates

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

Income Taxes

Deferred income taxes are provided to reflect the future tax consequences of differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Deferred income tax assets and liabilities are computed using the currently enacted tax laws and rates that apply to the periods in which they are expected to affect taxable income.

A valuation allowance is established when it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, and accounts payable. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable are representative of their respective fair values due to the short-term maturity of these instruments.

3. Related Parties

AMPCO Services LLC (Services)

Marathon and Noble, through their respective subsidiaries, formed Services to provide technical and consulting services to their jointly owned methanol production and marketing companies related to the transportation, storage, marketing, sale and delivery of methanol. Services bills the Company the cost, plus a 7% mark-up, of fixed asset purchases and expenses incurred on behalf of the Company, excluding depreciation. Services is equally owned by Noble and Marathon through their various subsidiaries.

At December 31, 2003, the Company had approximately $0.2 million in payables for consulting services received during 2003 by Services on behalf of the Company, which is included as accounts payable – affiliates on the accompanying balance sheet. During the year the Company incurred costs of approximately $2.6 million from Services. Such amounts are included in cost of methanol on the accompanying Statement of Operations.

AMPCO Marketing LLC (Marketing)

Effective January 1, 2001, the Company entered into an agreement to sell to Marketing 300,000 to 600,000 metric tons of methanol on an annual basis through 2005. The price received under the agreement is based on the price that Marketing is able to resell the methanol to third parties, less commissions, transportation and storage costs. In turn, Marketing has entered into annual contracts with third parties to sell methanol on a monthly basis. Pricing under these contracts is generally based on an index price less certain discounts for volume purchases. Marketing is equally owned by Noble and Marathon through their respective subsidiaries.

Marathon and Noble

Marathon and Noble, through their respective subsidiaries provide the Company with gas for use in the Plant from the nearby Alba Field. The gas is priced at $0.25 per MMBtu. The Alba Field is owned 63.3% and 33.7% by subsidiaries of Marathon and Noble, respectively (see Note 5).

4. Income Taxes

Under the Manufacturing and Marketing Agreement (MMA) entered into with the Republic of Equatorial Guinea, the Company is exempted from Republic corporate income taxes for three years after commercial operations begin. The three-year income tax holiday excludes the year of first commercial operation. Therefore, the Company will be liable for income taxes beginning in 2005. During the income tax holiday the Company is recording depreciation for book purposes but is not required to take any reductions to the related assets carrying value for tax purposes. Accordingly, the Company is creating a deferred tax asset equal to the amount of depreciation taken for book purposes multiplied by the statutory tax rate of 25%. As of December 31, 2003 this represents an asset of approximately $11,832,000. The Company has recognized a valuation allowance equal to the deferred tax asset due to the uncertainty of the timing of future earnings.

5. Commitments And Contingencies

Pursuant to the Company's Limited Liability Company Agreement, no member or manager shall be liable for the debts, obligations, or liabilities of the Company, including under a judgment, decree or order of a court, except as may be provided in a separate, written agreement executed by such member or manager wherein they expressly agree to assume such obligations. The Company will continue to exist in perpetuity absent unanimous approval of the Members.

Litigation

The Company is involved in disputes arising in the ordinary course of business. Management does not believe the outcome of any such disputes will have a material adverse effect on the Company's financial position or results of operations.

Gas Purchase Commitment

The Company has a take-or-pay commitment contract to purchase annual quantities of natural gas for use by the Plant. The term of the contract is 25 years from first supply (May 2, 2001) and can be extended based on agreement of the parties. The minimum annual contract quantity of gas that must be purchased is 28,000,000 MMBtu on a gross heating value basis from the Alba Field (see Note 1). The gas is priced at $0.25 per MMBtu. The Alba Field is owned 63.3% and 33.7% by subsidiaries of Marathon and Noble, respectively. The minimum commitment under this contract is as follows:

2004	$ 7,000,000
2005	7,000,000
2006	7,000,000
2007	7,000,000
2008	7,000,000
2009 and thereafter	121,333,000
	$ 156,333,000

Sales Commitments

In addition to the sales contract between the Company and Marketing disclosed in Note 3, the Company also entered into contracts with MG and British Petroleum Oil International (BP), unrelated third parties, to sell 300,000 and 80,000 metric tons, respectively, of methanol on an annual basis through 2005. The price received under the MG agreement is based on the price MG resells the methanol to third parties, less commissions, transportation and storage costs. In turn, MG has entered into annual contracts with third parties to sell methanol on a monthly basis. Pricing under MG's contracts with third parties are based upon annual contract discounts as applied to the quarterly European contract price. Several customers' contracts also include a spot component based upon the spot price at the time of purchase. In the case of BP, which internally consumes the methanol acquired, the price is based upon the European index with the spot price impacting the final price. In 2003, the BP contract contains a price cap of EURO 180 per ton of methanol sold.

Concentrations of Risk

The Company sells all of its production under agreements with Marketing, MG and BP, as previously disclosed, who in turn resell the methanol to numerous third parties. In addition, the Company's ability to produce methanol is dependant upon the natural gas feedstock received from the Alba Field as disclosed in Note 5.

6. Leases

The Company has leased office space from the Republic for use in training local employees for work at the Plant. The lease requires semi-annual payments of $120,000 and expires in August 2007.

The Company entered into operating lease agreements on March 23, 1999 for two oil/methanol tankers (vessels) to transport methanol produced by the Plant to the markets serviced by MG, BP and Marketing. Each vessel has a capacity of approximately 42,000 metric tons of methanol. The vessel lease agreements are for a period of 15 years and can be extended for an additional five-year period at the option of the Company. During the term of the leases, the Company is required to pay, for each vessel, $14,300 per day accelerating to $17,500 per day in year 11 of the leases. At any time during the term of the lease, the Company has the option to terminate the leases by giving three months written notice. To cancel one of the leases, the Company would also be required to make a lump-sum termination payment of the lesser of $10 million if cancelled during years one through eight, $8 million if cancelled during years nine through twelve, or $7 million if cancelled after twelve years. The cost of the vessel leases and related operation costs of the vessels are reflected as shipping expense on the accompanying statement of operations.

During periods of non-use, the Company has the option to sublease the vessels to other parties. Revenue associated with subleasing the vessels is reflected as shipping revenue on the accompanying statement of operations.

Future minimum lease payments under these leases are as follows:

2004	$ 12,869,000
2005	12,869,000
2006	12,869,000
2007	12,869,000
2008	12,869,000
2009 and thereafter	88,813,000
	$ 153,158,000

7. Bridge Cost Recovery Loss & Third Party Revenue & Cost

The Company uses Marketing to sell the Company's methanol in the United States. Sales contracts are typically negotiated in the third quarter of each year for the upcoming year's production and sold under calendar-year-basis agreements. Accordingly, sales contracts signed in the fall of 2002 applied to 2003 production. The Plant was shut in for one month during the year due to compressor repairs. As a result, the Company did not provide methanol to Marketing for sale under the annual sales contracts. Consequently, Marketing had to purchase methanol on the spot market for resale. The cost of the methanol, net of the price received by Marketing for sales under the sale commitments, was billed to the Company and is reflected as bridge cost recovery loss on the accompanying statement of operations.

Also as a result of the plant being shut in, the Company purchased methanol on the spot market to meet sales commitments in Europe that were entered into during 2003 by MG. The cost of the methanol purchased is reflected as cost of third-party purchased methanol sold and the associated revenue from the sale of this methanol is reflected as sales of purchased third-party methanol on the accompanying statement of operations.

8. Net Profit Interest

Under the Manufacturing and Marketing Agreement entered into with the Republic of Equatorial Guinea, the Republic is granted a Net Profit Interest equal to 10% of Net Profits. 2003 was the first year that the Net Profits Interest went into effect.

9. Shipping Revenue & Ship Charter Expense

During 2003 when the plant was shut in the Company subleased its methanol tankers. The revenue earned in subleasing the vessels is captured as Ship Charter Revenue. The associated cost is captured as Ship Charter Expense.

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

Effective May 14, 2002, the Board of Directors of Noble Energy, Inc., after careful consideration and based upon the recommendation of its Audit Committee, dismissed its current independent public accountant, Arthur Andersen LLP. This dismissal followed the decision by the Board of Directors to seek proposals from other independent auditors to audit the Company's consolidated financial statements for its fiscal year ended December 31, 2002.

Effective May 14, 2002, the Board of Directors, based on the recommendation of its Audit Committee, retained KPMG LLP as its independent auditor with respect to the audit of the Company's consolidated financial statements for its fiscal year ended December 31, 2002.

During the Company's fiscal year ended December 31, 2001, and during the subsequent interim period preceding the replacement of Arthur Andersen LLP, the Company had not consulted with KPMG LLP or other independent auditors regarding the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's financial statements.

Item 9a. Controls and Procedures.

Based on the evaluation of the Company's disclosure controls and procedures by Charles D. Davidson, the Company's principal executive officer, and James L. McElvany, the Company's principal financial officer, as of the end of the period covered by this report, each of them has concluded that the Company's disclosure controls and procedures are effective. There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter 2003 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The section entitled "Election of Directors" in the Registrant's proxy statement for the 2004 annual meeting of stockholders sets forth certain information with respect to the directors of the Registrant and is incorporated herein by reference. Certain information with respect to the executive officers of the Registrant is set forth under the caption "Executive Officers of the Registrant" in Part I of this report.

The section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in the Registrant's proxy statement for the 2004 annual meeting of stockholders sets forth certain information with respect to compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, and is incorporated herein by reference.

The section entitled "Corporate Governance" in the Registrant's proxy statement for the 2004 annual meeting of stockholders sets forth certain information required by this item and is incorporated herein by reference.

Item 11. Executive Compensation.

The section entitled "Executive Compensation" in the Registrant's proxy statement for the 2004 annual meeting of stockholders sets forth certain information with respect to the compensation of management of the Registrant, and except for the report of the Compensation, Benefits and Stock Option Committee of the Board of Directors and the information therein under "Executive Compensation--Performance Graph" is incorporated herein by reference.

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

The sections entitled "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Executive Officers" in the Registrant's proxy statement for the 2004 annual meeting of stockholders set forth certain information with respect to the ownership of the Registrant's common stock and are incorporated herein by reference.

Item 13. **Certain Relationships and Related Transactions.**

The section entitled "Certain Transactions" in the Registrant's proxy statement for the 2004 annual meeting of stockholders sets forth certain information with respect to certain relationships and related transactions, and is incorporated herein by reference.

Item 14. **Principal Accountant Fees and Services.**

The section entitled "Matters Relating to the Independent Auditors" in the Registrant's proxy statement for the 2004 annual meeting of stockholders sets forth certain information with respect to principal accountant fees and services, and is incorporated herein by reference.

PART IV

Item 15. **Exhibits, Financial Statement Schedules and Reports on Form 8-K.**

(a) The following documents are filed as a part of this report:

(1) Financial Statements and Financial Statement Schedules and Supplementary Data: These documents are listed in the Index to Financial Statements in Item 8 hereof.

(2) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

(b) Reports on Form 8-K:

(1) On October 29, 2003, the Company furnished on Form 8-K, pursuant to Item 12, Results of Operations and Financial Condition, and Item 7 (c), Financial Statements and Exhibits, a press release announcing its financial results for the third quarter of fiscal year 2003.

(2) On December 17, 2003, the Company furnished on Form 8-K, pursuant to Item 12, Results of Operations and Financial Condition, and Item 7 (c), Financial Statements and Exhibits, a press release updating its 2003 asset disposition program, related discontinued operations and the write-off of an investment in Vietnam.

SIGNATURES

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

NOBLE ENERGY, INC.
(Registrant)

Date: March 12, 2004

By: /s/ James L. McElvany
James L. McElvany,
Senior Vice President, Chief Financial Officer and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity in which signed	Date
/s/ Charles D. Davidson Charles D. Davidson	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	March 12, 2004
/s/ James L. McElvany James L. McElvany	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	March 12, 2004
/s/ Michael A. Cawley Michael A. Cawley	Director	March 12, 2004
/s/ Edward F. Cox Edward F. Cox	Director	March 12, 2004
/s/ James C. Day James C. Day	Director	March 12, 2004
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	March 12, 2004
/s/ Dale P. Jones Dale P. Jones	Director	March 12, 2004
/s/ Bruce A. Smith Bruce A. Smith	Director	March 12, 2004

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
3.1	--	Certificate of Incorporation, as amended, of the Registrant as currently in effect (filed as Exhibit 3.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1987 and incorporated herein by reference).
3.2	--	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant dated August 27, 1997 (filed Exhibit A of Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
3.3	--	Composite copy of Bylaws of the Registrant as currently in effect (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 29, 2002) dated February 8, 2002 and incorporated herein by reference).
3.4	--	Certificate of Designations of Series B Mandatorily Convertible Preferred Stock of the Registrant dated November 9, 1999 (filed as Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
4.1	--	Indenture dated as of October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7 1/4% Notes Due 2023, including form of the Registrant's 7 1/4% Notes Due 2023 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 and incorporated herein by reference).
4.2	--	Indenture relating to Senior Debt Securities dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.3	--	First Indenture Supplement relating to $250 million of the Registrant's 8% Senior Notes Due 2027 dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.4	--	Second Indenture Supplement, between the Company and U.S. Trust Company of Texas, N.A. as trustee, relating to $100 million of the Registrant's 7 1/4% Senior Debentures Due 2097 dated as of August 1, 1997 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 and incorporated herein by reference).
4.5	--	Rights Agreement, dated as of August 27, 1997, between the Registrant and Liberty Bank and Trust Company of Oklahoma City, N.A., as Right's Agent (filed as Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
4.6	--	Amendment No. 1 to Rights Agreement dated as of December 8, 1998, between the Registrant and Bank One Trust Company, as successor Rights Agent to Liberty Bank and Trust Company of Oklahoma City, N.A. (filed as Exhibit 4.2 to the Registrant's Registration Statement on Form 8-A/A (Amendment No. 1) filed on December 14, 1998 and incorporated herein by reference).
10.1 *	--	Restoration of Retirement Income Plan for Certain Participants in the Noble Energy, Inc. Retirement Plan dated September 21, 1994, effective as of May 19, 1994 (filed as Exhibit 10.5 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference).
10.2 *	--	Amendment No. 1 to the Restoration of Retirement Income Plan for Certain Participants in the Noble Affiliates Retirement Plan executed March 26, 2002 (filed as Exhibit 10.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).

Exhibit Number		Exhibit **
10.3 *	--	Noble Energy, Inc. Restoration Trust effective August 1, 2002 (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.4 *	--	Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates Thrift Restoration Plan dated May 9, 1994) as restated effective August 1, 2001 (filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.5 *	--	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended, dated January 27, 2003, and approved by the stockholders of the Company on April 29, 2003 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 and incorporated herein by reference).
10.9 *	--	1988 Nonqualified Stock Option Plan for Non-Employee Directors of the Registrant, as amended and restated, effective as of April 23, 2002 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 and incorporated herein by reference).
10.10*	--	Noble Energy, Inc. Non-Employee Director Fee Deferral Plan dated April 25, 2002 and effective as of April 23, 2002 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 and incorporated herein by reference).
10.11*	--	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report of Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.12	--	Guaranty of the Registrant dated October 28, 1982, guaranteeing certain obligations of Samedan (filed as Exhibit 10.12 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1993 and incorporated herein by reference).
10.13	--	Stock Purchase Agreement dated as of July 1, 1996, between Samedan Oil Corporation and Enterprise Diversified Holdings Incorporated (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Event: July 31, 1996) dated August 13, 1996 and incorporated herein by reference).
10.14	--	Noble Preferred Stock Remarketing and Registration Rights Agreement dated as of November 10, 1999 by and among the Registrant, Noble Share Trust, The Chase Manhattan Bank, and Donaldson, Lufkin & Jenrette Securities Corporation (filed as Exhibit 10.15 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
10.15*	--	Letter agreement dated February 1, 2002 between the Registrant and Charles D. Davidson, terminating Mr. Davidson's employment agreement and entering into the attached Change of Control Agreement (filed as Exhibit 10.17 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).
10.16*	--	Form of Change of Control Agreement entered into between the Registrant and each of the Registrant's officers, with schedule setting forth differences in Change of Control Agreements (filed as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).
10.17	--	Five-year Credit Agreement dated as of November 30, 2001 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Societe Generale, as the syndication agent for the lenders, Mizuho Financial Group, Credit Lyonnais, New York Branch, The Royal Bank of Scotland PLC, and Deutsche Bank Ag New York Branch, as co-documentation agents, and certain commercial lending institutions, as lenders (filed as Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).

Exhibit Number		Exhibit **
10.19	--	364-day Credit Agreement dated as of November 27, 2002 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Citibank, N.A., Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders, (filed as Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.20	--	364-day Credit Agreement dated as of October 30, 2003 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders, filed herewith.
12.1	--	Computation of ratio of earnings to fixed charges.
21	--	Subsidiaries, filed herewith.
23.1	--	Consent of KPMG LLP, filed herewith.
23.2	--	Consent of Ernst & Young LLP, filed herewith.
31.1	--	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2	--	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1	--	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2	--	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).

* Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

** Copies of exhibits will be furnished upon prepayment of 25 cents per page. Requests should be addressed to the Senior Vice President, Chief Financial Officer and Treasurer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067.

DIRECTORS

Charles D. Davidson
Chairman of the Board, President and
Chief Executive Officer,
Noble Energy, Inc.

Michael A. Cawley
Trustee, President and Chief Executive Officer,
The Samuel Roberts Noble Foundation, Inc.

Edward F. Cox
Partner, law firm of
Patterson, Belknap, Webb & Tyler LLP

James C. Day
Chairman of the Board and
Chief Executive Officer,
Noble Corporation

Kirby L. Hedrick
Former Executive Vice President,
Phillips Petroleum Company

Dale P. Jones
Consultant and former Vice Chairman
and President,
Halliburton Company

Bruce A. Smith
Chairman, President and Chief Executive
Officer,
Tesoro Petroleum Corporation

EXECUTIVE OFFICERS

Charles D. Davidson
Chairman of the Board, President,
Chief Executive Officer and Director
Noble Energy, Inc.

Alan R. Bullington
Vice President, International,
Noble Energy, Inc.

Robert K. Burleson
Vice President, Business Administration,
Noble Energy, Inc. and President,
Noble Energy Marketing, Inc.

Susan M. Cunningham
Senior Vice President, Exploration,
Noble Energy, Inc.

Arnold J. Johnson
Vice President, General Counsel
and Secretary,
Noble Energy, Inc.

James L. McElvany
Senior Vice President, Chief Financial Officer
and Treasurer,
Noble Energy, Inc.

Richard A. Peneguy, Jr.
Vice President, Offshore,
Noble Energy, Inc.

William A. Poillion, Jr.
Senior Vice President, Production and Drilling,
Noble Energy, Inc.

Ted A. Price
Vice President, Onshore,
Noble Energy, Inc.

David L. Stover
Vice President, Business Development,
Noble Energy, Inc.

Kenneth P. Wiley
Vice President, Information Systems,
Noble Energy, Inc.

CORPORATE AND SUBSIDIARY OFFICES

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Investor Relations
Greg Panagos
Director of Investor Relations
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KPMG LLP

Transfer Agent and Registrar
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Charlotte, North Carolina 28262-1153
(800) 829.8432
[illegible].whitley@wachovia.com

Common Stock Listed
New York Stock Exchange
Symbol – NBL

Annual Meeting
The Annual Meeting of Stockholders of Noble Energy, Inc. will be held on Tuesday, April 27, 2004, at 9:30 a.m. at the Goddard Center for the Visual and Performing Arts located at 401 First Street SW, Ardmore, OK 73401. All stockholders are cordially invited to attend.

Form 10-K
The Company's Annual Report on Form 10-K for the year ended December 31, 2003, as filed with the Securities and Exchange Commission, is included in this report. Additional copies are available without charge upon request by writing to the Chief Financial Officer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067, via the Company's Internet website: http://www.nobleenergyinc.com, or via the Securities and Exchange Commission's Internet website: http://www.sec.gov.

Design & Production: Pegasus Design, Inc., www.pegasusdesign.com

noble energy

CORPORATE HEADQUARTERS