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2003

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 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 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

NEW JERSEY (State or other jurisdiction of incorporation or organization)	13-5409005 (I.R.S. Employer Identification Number)

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298
(Address of principal executive offices) (Zip Code)
(972) 444-1000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (6,557,523,399 shares outstanding at February 29, 2004)	**New York Stock Exchange**
Registered securities guaranteed by Registrant:	
SeaRiver Maritime Financial Holdings, Inc.	
Twenty-Five Year Debt Securities due October 1, 2011	**New York Stock Exchange**
Exxon Capital Corporation	
Twelve Year 6% Notes due July 1, 2005	**New York Stock Exchange**

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes _✓_ No ____

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $35.91 on the New York Stock Exchange composite tape, was in excess of $238 billion.

Documents Incorporated by Reference:
Proxy Statement for the 2004 Annual Meeting of Shareholders (Part III)

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EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2003

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PART I

Item 1. *Business.*

Exxon Mobil Corporation, formerly named Exxon Corporation, was incorporated in the State of New Jersey in 1882. On November 30, 1999, Mobil Corporation became a wholly-owned subsidiary of Exxon Corporation, and Exxon changed its name to Exxon Mobil Corporation.

Divisions and affiliated companies of ExxonMobil operate or market products in the United States and about 200 other countries and territories. Their principal business is energy, involving exploration for, and production of, crude oil and natural gas, manufacture of petroleum products and transportation and sale of crude oil, natural gas and petroleum products. ExxonMobil is a major manufacturer and marketer of basic petrochemicals, including olefins, aromatics, polyethylene and polypropylene plastics and a wide variety of specialty products. ExxonMobil also has interests in electric power generation facilities. Affiliates of ExxonMobil conduct extensive research programs in support of these businesses.

Exxon Mobil Corporation has several divisions and hundreds of affiliates, many with names that include *ExxonMobil*, *Exxon*, *Esso* or *Mobil*. For convenience and simplicity, in this report the terms *ExxonMobil*, *Exxon*, *Esso* and *Mobil*, as well as terms like *corporation*, *company*, *our*, *we* and *its*, are sometimes used as abbreviated references to specific affiliates or groups of affiliates. The precise meaning depends on the context in question.

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on the air, water and ground. This includes a significant investment in refining technology to manufacture low-sulfur motor fuels and projects to reduce nitrogen oxide and sulfur oxide emissions. ExxonMobil's 2003 worldwide environmental costs for all such preventative and remediation steps were about $2.8 billion, of which $1.3 billion were capital expenditures and $1.5 billion were included in expenses. The total cost for such activities is expected to decrease to about $2.6 billion in both 2004 and 2005 (with capital expenditures representing just over 40 percent of the total). The projected decrease reflects the near completion of low-sulfur motor fuels projects in Canada and the U.S., partly offset by increases in Europe and Japan.

Operating data and industry segment information for the corporation are contained on pages 66, 67, 69 and 75; information on oil and gas reserves is contained on pages 72 and 73 and information on company-sponsored research and development activities is contained on page 50 of the Financial Section of this report.

The number of regular employees was 88.3 thousand, 92.5 thousand and 97.9 thousand at years ended 2003, 2002 and 2001, respectively. Regular employees are defined as active executive, management, professional, technical and wage employees who work full-time or part-time for the company and are covered by the company's benefit plans and programs. Regular employees do not include employees of the company-operated retail sites (CORS). The number of CORS employees was 17.4 thousand, 16.8 thousand and 19.9 thousand at years ended 2003, 2002 and 2001, respectively.

ExxonMobil maintains a website at www.exxonmobil.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commission. Also available on the corporation's website are the company's Corporate Governance Guidelines and Code of Ethics and Business Conduct, as well as the charters of the audit, compensation and nominating committees of the board of directors. All of these documents are available in print for any shareholder who requests them. Information on our website is not incorporated into this report.

Factors Affecting Future Results

Competitive Factors: The energy and petrochemical industries are highly competitive. There is competition within the industries and also with other industries in supplying the energy, fuel and

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chemical needs of industry and individual consumers. The corporation competes with other firms in the sale or purchase of various goods or services in many national and international markets and employs all methods of competition which are lawful and appropriate for such purposes. A key component of the corporation's competitive position, particularly given the commodity-based nature of many of its products, is its ability to manage expenses successfully, which requires continuous management focus on reducing unit costs and improving efficiency.

Political Factors: The operations and earnings of the corporation and its affiliates throughout the world have been, and may in the future be, affected from time to time in varying degree by political instability and by other political developments and laws and regulations, such as forced divestiture of assets; restrictions on production, imports and exports; war or other international conflicts; civil unrest and local security concerns that threaten the safe operation of company facilities; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights; and environmental regulations. Both the likelihood of such occurrences and their overall effect upon the corporation vary greatly from country to country and are not predictable.

Industry and Economic Factors: The operations and earnings of the corporation and its affiliates throughout the world are affected by local, regional and global events or conditions that affect supply and demand for oil, natural gas, petroleum products, petrochemicals and other ExxonMobil products. These events or conditions are generally not predictable and include, among other things, general economic growth rates and the occurrence of economic recessions; the development of new supply sources; adherence by countries to OPEC quotas; supply disruptions; weather, including seasonal patterns that affect energy demand and severe weather events that can disrupt operations; technological advances, including advances in exploration, production, refining, and petrochemical manufacturing technology and advances in technology relating to energy usage; changes in demographics, including population growth rates and consumer preferences; and the competitiveness of alternative hydrocarbon or other energy sources or product substitutes.

Project Factors: In addition to the factors cited above, the advancement, cost and results of particular ExxonMobil projects depend on the outcome of negotiations with partners, governments, suppliers, customers or others; changes in operating conditions or costs; changes in rates of field decline; and the occurrence of unforeseen technical difficulties. See section 1 of Item 2 of this report for discussion of additional factors affecting the timing and ultimate recovery of reserves.

Market Risk Factors: See pages 37 and 38 of the Financial Section of this report for discussion of the impact of market risks, inflation and other uncertainties.

Projections, estimates and descriptions of ExxonMobil's plans and objectives included or incorporated in Items 1, 2, 7 and 7A of this report are forward-looking statements. Actual future results, including project completion dates, production rates, capital expenditures, costs and business plans could differ materially due to, among other things, the factors discussed above and elsewhere in this report.

Item 2. ***Properties.***

Part of the information in response to this item and to the Securities Exchange Act Industry Guide 2 is contained in the Financial Section of this report in Note 10, which note appears on page 52, and on pages 70 through 75.

Information with regard to oil and gas producing activities follows:

1. Net Reserves of Crude Oil and Natural Gas Liquids (millions of barrels) and Natural Gas (billions of cubic feet) at Year-End 2003

Estimated proved reserves are shown on pages 72 and 73 of the Financial Section of this report. No major discovery or other favorable or adverse event has occurred since December 31, 2003, that

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would cause a significant change in the estimated proved reserves as of that date. For information on the standardized measure of discounted future net cash flows relating to proved oil and gas reserves, see page 74 of the Financial Section of this report.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations and extrapolations of well information such as flow rates and reservoir pressure declines. In certain deepwater fields, proved reserves are recorded in a limited number of cases before flow tests are conducted because of the safety and cost implications of conducting the tests. In those situations, other industry accepted analyses are used such as information from well logs, a thorough pressure and fluid sampling program, conventional core data obtained across the entire reservoir interval and nearby analog data. Historically, proved reserves recorded using these methods have been immaterial when compared to the corporation's total proved reserves and have also been validated by subsequent flow tests or actual production levels. Furthermore, the corporation only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. Although the corporation is reasonably certain that proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in projections of long term oil and gas price levels.

2. Estimates of Total Net Proved Oil and Gas Reserves Filed with Other Federal Agencies

During 2003, ExxonMobil filed proved reserves estimates with the U.S. Department of Energy on Forms EIA-23 and EIA-28. The information on Form EIA-28 is presented on the same basis as the registrant's Annual Report on Form 10-K for 2002, which shows ExxonMobil's net interests in all liquids and gas reserve volumes and changes thereto from both ExxonMobil-operated properties and properties operated by others. The data on Form EIA-23, although consistent with the data on Form EIA-28, is presented on a different basis, and includes 100 percent of the oil and gas volumes from ExxonMobil-operated properties only, regardless of the company's net interest. In addition, Form EIA-23 information does not include gas plant liquids. The difference between the oil reserves reported on EIA-23 and those reported in the registrant's Annual Report on Form 10-K for 2002 exceeds five percent. The difference in gas reserves did not exceed five percent.

3. Average Sales Prices and Production Costs per Unit of Production

Reference is made to page 70 of the Financial Section of this report. Average sales prices have been calculated by using sales quantities from the corporation's own production as the divisor. Average production costs have been computed by using net production quantities for the divisor. The volumes of crude oil and natural gas liquids (NGL) production used for this computation are shown in the reserves table on page 72 of the Financial Section of this report. The net production volumes of natural gas available for sale used in this calculation are shown on page 75 of the Financial Section of this report. The volumes of natural gas were converted to oil-equivalent barrels based on a conversion factor of six thousand cubic feet per barrel.

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4. Gross and Net Productive Wells

	Year-End 2003				Year-End 2002			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	33,716	13,188	9,566	5,746	34,737	13,509	9,564	5,614
Canada	7,037	5,770	5,317	2,666	6,719	5,421	5,268	2,623
Europe	1,873	604	1,387	524	1,839	593	1,398	531
Asia-Pacific	1,509	553	853	306	1,463	557	815	288
Africa	355	152	16	7	373	160	3	1
Other	1,239	224	101	30	1,181	221	103	32
Total	45,729	20,491	17,240	9,279	46,312	20,461	17,151	9,089

The numbers of wells operated at year-end 2003 were 20,174 gross wells and 16,610 net wells. At year-end 2002, the numbers of operated wells were 20,322 gross wells and 16,479 net wells.

5. Gross and Net Developed Acreage

	Year-End 2003		Year-End 2002	
	Gross	Net	Gross	Net
	(Thousands of acres)			
United States	9,367	5,655	9,451	5,695
Canada	4,786	2,431	4,720	2,356
Europe	11,296	4,746	11,842	4,874
Asia-Pacific	5,443	1,723	5,393	1,692
Africa	1,130	462	2,251	685
South America	1,331	388	1,331	388
Middle East	7,405	1,356	7,405	1,354
Caspian	487	103	487	103
Total	41,245	16,864	42,880	17,147

Note: Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

6. Gross and Net Undeveloped Acreage

	Year-End 2003		Year-End 2002	
	Gross	Net	Gross	Net
	(Thousands of acres)			
United States	11,343	7,353	11,396	7,309
Canada	9,078	5,055	18,704	8,701
Europe	8,555	2,611	9,305	2,687
Asia-Pacific	17,457	8,769	24,127	12,163
Africa	28,423	11,447	29,488	12,205
South America	15,650	15,141	23,845	17,459
Middle East	36	10	36	10
Caspian	2,561	516	2,611	543

Total	93,103	50,902	119,512	61,077

7. Summary of Acreage Terms in Key Areas

UNITED STATES

Oil and gas leases have an exploration period ranging from one to ten years, and a production period that normally remains in effect until production ceases. In some instances, a “fee interest” is acquired where both the surface and the underlying mineral interests are owned outright.

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CANADA

Exploration permits are granted for varying periods of time with renewals possible. Production leases are held as long as there is production on the lease. The majority of Cold Lake leases were taken for an initial 21-year term in 1968-1969 and renewed for a second 21-year term in 1989-1990. The exploration acreage in Eastern Canada is currently held by work commitments of various amounts.

EUROPE

France

Exploration permits are granted for periods of three to five years, and are renewable up to two times accompanied by substantial acreage relinquishments: 50 percent of the acreage at first renewal; 25 percent of the remaining acreage at second renewal. A 1994 law requires a bidding process prior to granting of an exploration permit. Upon discovery of commercial hydrocarbons, a production concession is granted for up to 50 years, renewable in periods of 25 years each.

Germany

Exploration concessions are granted for an initial maximum period of five years with possible extensions of up to three years for an indefinite period. Extensions are subject to specific, minimum work commitments. Production licenses are normally granted for 20 to 25 years with multiple possible extensions as long as there is production on the license.

Italy

Exploration permits are awarded for a period of six years, subject to specific, minimum work commitments (an exploration well is usually included). If permit obligations have been fulfilled, the titleholder of the permit is entitled to two subsequent extensions of three years each. The program of both the first and second extension period must include the drilling of a further well. Production licenses are awarded for a period of 20 years upon discovery of commercial hydrocarbons. After 15 years, the license holder can apply for an extension of ten years. After seven years of the first extension period, the license holder can apply for a further extension of five years.

Netherlands

Under the new Mining Law, effective January 1, 2003, exploration and production licenses for both onshore and offshore areas are issued for a period of time necessary to perform the activities for which the license is issued. License conditions are stipulated in the Mining Law.

Exploration and production rights granted prior to January 1, 2003 remain subject to their existing terms, and differ slightly for onshore and offshore areas.

Onshore: Exploration licenses were issued for a period of time necessary to perform the activities for which the license was issued. Production concessions are granted after discoveries have been made, under conditions that are negotiated with the government. Normally, they are field-life concessions covering an area defined by hydrocarbon occurrences.

Offshore: Exploration licenses issued between 1976 and 1996 were for a ten-year period, with relinquishment of about 50 percent of the original area required at the end of six years. Exploration licenses granted after that time were for a period of time necessary to perform the activities for which the permit was issued. Production licenses are normally issued for a 40-year period.

Norway

Licenses issued prior to 1972 were for an initial period of six years and an extension period of 40 years, with relinquishment of at least one-fourth of the original area required at the end of the sixth year

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and another one-fourth at the end of the ninth year. Licenses issued between 1972 and 1997 were for an initial period of up to six years (with extension of the initial period of one year at a time up to ten years after 1985), and an extension period of up to 30 years, with relinquishment of at least one-half of the original area required at the end of the initial period. Licenses issued after July 1, 1997 have an initial period of up to ten years and a normal extension period of up to 30 years or in special cases of up to 50 years, and with relinquishment of at least one-half of the original area required at the end of the initial period.

United Kingdom

Acreage terms are fixed by the government and are periodically changed. For example, the regulations governing licenses issued between 1996 and 1998 provided for an initial term of three years with possible extensions of six, 15 and 24 years for a license period of 45 more years. After the second extension, the license must be surrendered in part. Licenses issued in 2002 as part of the 20th licensing round have an initial term of four years with a second term extension of four years. There is a mandatory relinquishment of all acreage that is not covered by a development plan at the end of the second term.

ASIA-PACIFIC

Australia

Onshore: Acreage terms are fixed by the individual state and territory governments. These terms and conditions vary significantly between the states and territories. Exploration permits are normally granted for two to six years (in some states the responsible Minister fixes the term) with possible renewals and relinquishment. Production licenses in South Australia are granted for an unlimited term, subject to meeting stipulated conditions in the license, including production and expenditure requirements. Production licenses in Queensland are granted for varying periods consistent with expected field lives, with renewals on a similar basis.

Offshore: Exploration and production activities beyond the three nautical mile limit are governed by Federal legislation applicable to all ExxonMobil's offshore acreage. Exploration permits granted before January 1, 2003 were issued for six years with three possible five-year renewal periods. Exploration permits granted after that date are issued for six years with two possible five-year renewal periods. A 50 percent relinquishment of remaining area is mandatory at the end of each renewal period. Retention leases may be granted for resources that are not commercially viable at the time of application, but are expected to become commercially viable within 15 years. These are granted for periods of five years and renewals may be requested. Prior to September 1998, production licenses were granted initially for 21 years, with a further renewal of 21 years and thereafter renewals at the discretion of the Joint Authority, comprising Federal and State Ministers. Effective from September 1998, new production licenses are granted "indefinitely", i.e., for the life of the field (if no operations for the recovery of petroleum have been carried on for five years, the license may be terminated).

Indonesia

Exploration and production activities in Indonesia are generally governed by cooperation contracts, usually in the form of a production sharing contract, negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. Formerly this activity was carried out by Pertamina, the government owned oil company, which is now a competing limited liability company.

Japan

The Mining Law provides for the granting of concessions that convey exploration and production rights. Exploration rights are granted for an initial two-year period, and may be extended for two two-

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year periods for gas and three two-year periods for oil. Production rights have no fixed term and continue until abandonment so long as the rights holder is fulfilling its obligations.

Malaysia

Exploration and production activities are governed by production sharing contracts negotiated with the national oil company. The more recent contracts have an overall term of 24 to 38 years with possible extensions to the exploration and/or development periods. The exploration period is five to seven years with the possibility of extensions, after which time areas with no commercial discoveries will be deemed relinquished. The development period is from four to six years from commercial discovery, with the possibility of extensions under special circumstances. Areas from which commercial production has not started by the end of the development period will be deemed relinquished if no extension is granted. All extensions are subject to the national oil company's prior written approval. The total production period is 15 to 25 years from first commercial lifting, not to exceed the overall term of the contract.

Papua New Guinea

Exploration and production activities are governed by the Oil and Gas Act. Petroleum Prospecting licenses are granted for an initial term of six years with a five-year extension possible. Generally, a 50 percent relinquishment of the license area is required at the end of the initial six year-term, if extended. Petroleum Development licenses are granted for an initial 25-year period. An extension of up to 20 years may be granted at the Minister's discretion. Petroleum Retention licenses may be granted for gas resources that are not commercially viable at the time of application, but may become commercially viable. Petroleum Retention licenses are granted for five-year terms, and may be extended twice for a maximum retention time of 15 years.

Russia

Acreage terms are fixed by the production sharing agreement (PSA) that became effective in 1996 between the Russian government and the Sakhalin I consortium, of which ExxonMobil is the operator. The term of the PSA is 20 years from the Declaration of Commerciality, or until 2021. The term may be extended thereafter in 10-year increments as specified in the PSA.

Thailand

The Petroleum Act of 1971 allows production under ExxonMobil's concession for 30 years (through 2021) with a possible ten-year extension at terms generally prevalent at the time.

AFRICA

Angola

Exploration and production activities are governed by production sharing agreements with an initial exploration term of four years and an optional second phase of two to three years. The production period is for 25 years and agreements generally provide for a negotiated extension.

Cameroon

Exploration and production activities are governed by various agreements negotiated with the national oil company and the government of Cameroon. Exploration permits are granted for terms from four to 16 years and are generally renewable for multiple periods up to four years each. Upon commercial discovery, mining concessions are issued for a period of 25 years with one 25-year extension.

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Chad

Exploration permits are issued for a period of five years, and are renewable for one or two further five-year periods. The terms and conditions of the permits, including relinquishment obligations, are specified in a negotiated Convention. The production term is for 30 years and may be extended at the discretion of the government.

Equatorial Guinea

Exploration and production activities are governed by production sharing contracts negotiated with the State Ministry of Mines and Energy. The exploration periods are for ten to 15 years with limited relinquishments in the absence of commercial discoveries. The production period for crude oil is 30 years while the production period for gas is 50 years.

Nigeria

Exploration and production activities in the deepwater offshore areas are typically governed by production sharing contracts (PSCs) with the national oil company. The national oil company holds the underlying Oil Prospecting License (OPL) and any resulting Oil Mining Lease (OML). The terms of the PSCs are generally 30 years, including a ten-year exploration period (an initial exploration phase plus one or two optional periods) covered by an OPL. Upon commercial discovery, an OPL may be converted to an OML. Partial relinquishment is required under the PSC at the end of the ten-year exploration period, and OMLs have a 20-year production period that may be extended.

Some exploration activities are carried out in deepwater by joint ventures with local companies holding interests in an OPL. OPLs in deepwater offshore areas are valid for ten years and are non-renewable, while in all other areas the licenses are for five years and also are non-renewable. Demonstrating a commercial discovery is the basis for conversion of an OPL to an OML.

OMLs granted prior to the 1969 Petroleum Act (i.e., under the Mineral Oils Act 1914, repealed by the 1969 Petroleum Act) were for 30 years onshore and 40 years in offshore areas and are renewable upon 12 months' written notice, for further periods of 30 and 40 years, respectively.

OMLs granted under the 1969 Petroleum Act, which include all deepwater OMLs, have a maximum term of 20 years without distinction for onshore or offshore location and are renewable, upon 12 months' written notice, for another period of 20 years. OMLs not held by the national oil company are also subject to a mandatory 50 percent relinquishment after the first ten years of their duration.

The Memorandum of Understanding (MOU) defining commercial terms applicable to existing oil production was renegotiated and executed in 2000. The MOU is effective for a minimum of three years with possible extensions on mutual agreement and is terminable on one calendar year's notice.

SOUTH AMERICA

Argentina

The onshore concession terms in Argentina are up to four years for the initial exploration period, up to three years for the second exploration period and up to two years for the third exploration period. A 50 percent relinquishment is required after each exploration period. An extension after the third exploration period is possible for up to five years. The total production term is 25 years with a ten-year extension possible, once a field has been developed.

Venezuela

Exploration and production activities are governed by contracts negotiated with the national oil company. Exploration activity is covered by risk/profit sharing contracts where exploration blocks are

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awarded for 35 years. Production licenses are awarded for 20 years under production service agreements.

Strategic association agreements (such as the Cerro Negro project) are typically limited to those projects that require vertical integration for extra heavy crude oil. Contracts are awarded for 35 years. Significant amendments to the contract terms require Venezuelan congressional approval.

MIDDLE EAST

Qatar

The State of Qatar grants gas production development projects rights to develop and supply gas from the offshore North Field to permit the economic development and production of gas reserves sufficient to satisfy the gas and LNG sales obligations of these projects.

Republic of Yemen

Production sharing agreements (PSAs) negotiated with the government entitle the company to participate in exploration operations within a designated area during the exploration period. In the event of a commercial oil discovery, the company is entitled to proceed with development and production operations during the development period. The length of these periods and other specific terms are negotiated prior to executing the PSA. Existing production operations have a development period extending 20 years from first commercial declaration made in November 1985 for the Marib PSA and June 1995 for the Jannah PSA.

United Arab Emirates

Exploration and production activities in the Emirate of Abu Dhabi are governed by a 75-year oil concession agreement executed in 1939 and subsequently amended through various agreements with the government of Abu Dhabi.

CASPIAN

Azerbaijan

The production sharing agreement (PSA) for the development of the Azeri-Chirag-Gunashli field (commonly known as the Megastructure) is established for an initial period of 30 years starting from the PSA execution date in 1994.

Other exploration and production activities are governed by PSAs negotiated with the national oil company of Azerbaijan. The exploration period consists of three or four years with the possibility of a one to three-year extension. The production period, which includes development, is for 25 years or 35 years with the possibility of one or two five-year extensions.

Kazakhstan

Onshore: Exploration and production activities are governed by the production license and joint venture agreements negotiated with the Republic of Kazakhstan. Existing production operations have a 40-year production period that commenced in 1993.

Offshore: Exploration and production activities are governed by a production sharing agreement negotiated with the Republic of Kazakhstan. The exploration period is six years with the possibility of a two-year extension. The production period, which includes development, is for 20 years with the possibility of two ten-year extensions.

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8. Number of Net Productive and Dry Wells Drilled

	2003	2002	2001
A. Net Productive Exploratory Wells Drilled			
United States	13	12	4
Canada	13	20	30
Europe	4	2	3
Asia-Pacific	2	2	7
Africa	4	10	4
Other	2	—	3
Total	38	46	51
B. Net Dry Exploratory Wells Drilled			
United States	10	5	4
Canada	9	4	22
Europe	3	4	3
Asia-Pacific	3	1	2
Africa	3	5	4
Other	—	4	6
Total	28	23	41
C. Net Productive Development Wells Drilled			
United States	598	709	733
Canada	297	430	451
Europe	36	36	32
Asia-Pacific	50	67	44
Africa	59	27	23
Other	20	18	30
Total	1,060	1,287	1,313
D. Net Dry Development Wells Drilled			
United States	14	18	14
Canada	16	8	6
Europe	2	2	3
Asia-Pacific	—	1	1
Africa	1	—	—
Other	1	—	—
Total	34	29	24
Total number of net wells drilled	1,160	1,385	1,429

9. Present Activities

A. Wells Drilling

	Year-End 2003		Year-End 2002	
	Gross	Net	Gross	Net
United States	132	62	157	75
Canada	152	92	51	37

Europe	38	12	45	17
Asia-Pacific	10	5	10	6
Africa	78	27	78	31
Other	42	6	33	5
Total	452	204	374	171

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B. Review of Principal Ongoing Activities in Key Areas

During 2003, ExxonMobil's activities were conducted, either directly or through affiliated companies, by ExxonMobil Exploration Company (for exploration), by ExxonMobil Development Company (for large development activities), by ExxonMobil Production Company (for producing and smaller development activities) and by ExxonMobil Gas & Power Marketing Company (for gas marketing). During this same period, some of ExxonMobil's exploration, development, production and gas marketing activities were also conducted in Canada by the Resources Division of Imperial Oil Limited, which is 69.6 percent owned by ExxonMobil.

Some of the more significant ongoing activities are set forth below:

UNITED STATES

Exploration and delineation of additional hydrocarbon resources continued in 2003. At year-end 2003, ExxonMobil's acreage totaled 13.0 million net acres, of which 3.5 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska. A total of 23.3 net exploration and delineation wells were completed during 2003.

During 2003, 564.2 net development wells were completed within and around mature fields in the inland lower 48 states and 9.0 net development wells were completed offshore in the Pacific. Construction has begun on an acid gas injection project to increase existing plant capacity at the Shute Creek treating facility in LaBarge, Wyoming. Participation in Alaska production and development continued and a total of 24.0 net development wells were drilled. On Alaska's North Slope, activity continued in the Orion field with development drilling, the initiation of a new 3D seismic survey and conceptual engineering for facility expansions.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2003 was 3.4 million acres. A total of 14.1 net development wells were completed during the year and development continued on several Gulf of Mexico projects. Production began from the first phase of the Princess subsea development in December 2003 and construction of the semi-submersible production and drilling vessel continued at the Thunder Horse development.

CANADA

ExxonMobil's year-end acreage holdings totaled 7.5 million net acres, of which 3.0 million net acres were offshore. A total of 335.0 net exploration and development wells were completed during the year.

Gross production from Cold Lake averaged 130 thousand barrels per day during 2003. In Eastern Canada, the Alma field of the Sable Offshore Energy Project came online and the development of the next field in the project, South Venture, is underway.

EUROPE

France

ExxonMobil's acreage at year-end 2003 was 0.1 million net onshore acres, with 1.5 net development wells completed during the year.

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Germany

A total of 2.3 million net onshore acres and 0.2 million net offshore acres were held by ExxonMobil at year-end 2003, with 2.9 net development wells drilled during the year.

Italy

ExxonMobil's acreage was 30 thousand net onshore acres at year-end 2003.

Netherlands

ExxonMobil's interest in licenses totaled 2.0 million net acres at year-end 2003, 1.5 million acres onshore and 0.5 million acres offshore. During 2003, 5.3 net exploration and development wells were drilled. Offshore, the K/15-FK field began production and the K/7-FB platform was set and production started up. Onshore, a multi-year upgrade of the Groningen field facilities and adding additional compression is progressing.

Norway

ExxonMobil's net interest in licenses at year-end 2003 totaled 1.0 million acres, all offshore. ExxonMobil participated in 14.7 net exploration and development well completions in 2003. Production was initiated at Ringhorne in February 2003 and Grane, Fram West, Mikkel and Vigdis Extension in September/October 2003. Field development projects at Kristin, Ormen Lange, Ringhorne Jurassic, Sleipner West Compression, Sleipner West Alpha North, Oseberg J and Aasgard Q are in progress.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2003 totaled approximately 1.7 million acres, all offshore. A total of 20.6 net exploration and development wells were completed during the year. Several projects initiated first production in 2003 including Penguins, Carrack and Scoter. Other key projects underway are Goldeneye and Arthur.

ASIA-PACIFIC

Australia

ExxonMobil's net year-end 2003 acreage holdings totaled 3.5 million acres, 2.1 million acres onshore and 1.4 million acres offshore. ExxonMobil drilled a total of 17.0 net exploration and development wells in 2003, both offshore and onshore.

Indonesia

ExxonMobil had acreage of 5.7 million net acres at year-end 2003, 4.7 million acres offshore and 1.0 million acres onshore. A total of 10.0 net exploration and development wells were drilled during the year.

Japan

ExxonMobil's net offshore acreage was 36 thousand acres at year-end 2003.

Malaysia

ExxonMobil had interests in production sharing contracts covering 0.5 million net acres offshore Malaysia at year-end 2003. During the year, a total of 27.9 net development wells were completed. Development and infill drilling were successfully completed at twelve platforms. First oil was produced from Irong Barat-B, Raya-B and Angsi-E. Bintang-A and Bintang-B also started producing gas in 2003.

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Papua New Guinea

A total of 0.6 million net onshore acres were held by ExxonMobil at year-end 2003, with 0.5 net exploration and development wells completed during the year.

Russia

ExxonMobil's net acreage holdings at year-end 2003 were 0.1 million acres, all offshore. Construction and drilling activities have commenced on Phase 1 of Sakhalin I. Phase 1 facilities will include an offshore platform, onshore drill site for extended reach drilling to offshore oil zones, an onshore processing plant, an oil pipeline from Sakhalin Island to the Russian mainland and a mainland terminal for shipment of oil by tanker.

Thailand

ExxonMobil's net onshore acreage in the Khorat concession totaled 21 thousand acres at year-end 2003.

AFRICA

Angola

ExxonMobil's year-end 2003 acreage holdings totaled 1.3 million net offshore acres and 6.9 net exploration and development wells were completed during the year. Production began at the ExxonMobil-operated Xikomba development in Block 15 and at the non-operated Jasmim development on Block 17. Construction is underway on ExxonMobil-operated Kizomba A and Kizomba B, both on Block 15. In addition, engineering and design work is proceeding on Dalia, a non-operated Block 17 discovery.

Cameroon

ExxonMobil's acreage totaled 0.3 million net offshore acres at year-end 2003, with 1.0 net exploratory well completed during the year.

Chad

ExxonMobil's net year-end 2003 acreage holdings consisted of 4.1 million onshore acres, with 33.6 net exploration and development wells completed during the year. The ExxonMobil-operated Chad-Cameroon oil development and pipeline project began the early production phase in 2003, with start-up of the Miandoum field. Drilling and facility construction for the full production phase of the project continued through 2003.

Equatorial Guinea

ExxonMobil's acreage totaled 0.7 million net offshore acres at year-end 2003, with 15.0 net development wells completed during the year. Production from the Southern Expansion Area of the Zafiro Field began in July 2003.

Nigeria

ExxonMobil's net acreage totaled 1.7 million offshore acres at year-end 2003, with 10.5 net exploration and development wells completed during the year. The ExxonMobil-operated Yoho field (OML 104) that commenced production during December 2002 through the Early Production System (EPS), reached peak EPS volumes in 2003 and full field facility construction is underway. The Amenam-Kpono joint development project (OML 70 and OML 99) commenced production during July 2003. Construction, installation and drilling activities continue at the Bonga field (OML 118) and construction activities are underway on the ExxonMobil-operated Erha field (OPL 209). Equipment procurement and detailed engineering are underway for the ExxonMobil-operated East Area Oil Recovery Project.

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OTHER COUNTRIES

Argentina

ExxonMobil's net acreage totaled 0.3 million onshore acres at year-end 2003 with 0.2 net exploratory wells completed during the year.

Azerbaijan

At year-end 2003, ExxonMobil's net acreage, located in the Caspian Sea offshore of Azerbaijan, totaled 0.1 million acres. During the year, 0.4 net development wells were completed. At the Azeri-Chirag-Gunashli (ACG) Early Oil project, oil production with pressure support from water injection is ongoing. Engineering and construction is underway on the first and second phases of full field development at ACG.

Kazakhstan

ExxonMobil's net acreage totaled 0.3 million acres onshore and 0.2 million acres offshore at year-end 2003, with 2.2 net exploration and development wells completed during 2003. At Tengiz, construction of the 10.0 MTA (million metric tons per annum; 1 MTA is approximately 22 thousand barrels per day) expansion project began in 2003. Front end engineering design has been completed on the initial phase of the offshore Kashagan field. Key technical documents supporting the development were submitted to the government and approved in 2003. Approval of the field's development plan by the Republic of Kazakhstan was received in February 2004.

Qatar

Production and development activities continued on four major Liquefied Natural Gas (LNG) projects in Qatar Liquefied Gas Company Limited and Qatar Liquefied Gas Company Limited (II) (two "Qatargas" projects) and in Ras Laffan Liquefied Natural Gas Company Ltd. and Ras Laffan Liquefied Natural Gas Company Ltd. (II) (two "RasGas" projects).

The capacity numbers quoted below are in million metric tons per annum (MTA). This represents the amount of liquefied natural gas that can be sold at the outlet of the LNG plant. The factor to convert MTA to cubic feet is dependent on gas quality, mix of fields and production facility design. The conversion factor for Qatargas trains 1-3 and RasGas trains 1 and 2 is 46 GCF (billion cubic feet) equals 1 MTA; RasGas train 3 is 46.6 GCF and RasGas train 4 is 49.4 GCF.

Production levels from the Qatargas LNG facilities, which include three LNG trains with a total combined production capacity of 8.9 MTA LNG plus associated condensate, continued to increase through 2003. This is a result of progress debottlenecking the existing trains. The debottlenecking project is targeted for completion in mid-2005, at which point the overall capacity of the Qatargas facilities will exceed 8.9 MTA.

The RasGas facilities currently includes two LNG trains with a total combined production capacity of 6.6 MTA LNG plus associated condensate. In an ongoing expansion, construction progressed on the third and fourth RasGas trains, both with a planned capacity of 4.7 MTA.

In addition to LNG production in Qatar, ExxonMobil is currently constructing gas production facilities (the Al Khaleej Gas Project) to supply sales gas to domestic industrial customers.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 0.9 million acres onshore at year-end 2003. During the year, 9.3 net development wells were drilled and completed.

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United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi onshore oil concession was 0.5 million acres at year-end 2003. During the year, 7.0 net exploratory and development wells were completed. Engineering, procurement and construction contracts were awarded for the North East Bab Phase I development project and for the Bab Facility Expansion project.

Venezuela

ExxonMobil's net year-end 2003 acreage holdings totaled 0.2 million onshore acres, with 0.3 net development wells completed during the year.

WORLDWIDE EXPLORATION

At year-end 2003, exploration activities were underway in several areas in which ExxonMobil has no established production operations. A total of 18.8 million net acres were held at year-end 2003, and 1.5 net exploration wells were completed during the year.

Information with regard to mining activities follows:

Syncrude Operations

Syncrude is a joint venture established to recover shallow deposits of tar sands using open-pit mining methods, to extract the crude bitumen, and to produce a high-quality, light (32 degree API), sweet, synthetic crude oil. The Syncrude operation, located near Fort McMurray, Alberta, Canada, exploits a portion of the Athabasca Oil Sands Deposit. The location is readily accessible by public road. The produced synthetic crude oil is shipped from the Syncrude site to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd. Since start-up in 1978, Syncrude has produced about 1.5 billion barrels of synthetic crude oil. Imperial Oil Limited is the owner of a 25 percent interest in the joint-venture. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited.

Operating License and Leases

Syncrude has an operating license issued by the Province of Alberta which is effective until 2035. This license permits Syncrude to mine tar sands and produce synthetic crude oil from approved development areas on tar sands leases. Syncrude holds eight tar sands leases covering approximately 252,000 acres in the Athabasca Oil Sands Deposit. Issued by the Province of Alberta, the leases are automatically renewable as long as tar sands operations are ongoing or the leases are part of an approved development plan. Syncrude leases 10, 12, 17, 22 and 34 (containing proven reserves) and leases 29, 30 and 31 (containing no proven reserves) are included within a development plan approved by the Province of Alberta. There were no known previous commercial operations on these leases prior to the start-up of operations in 1978.

Operations, Plant and Equipment

Operations at Syncrude involve three main processes: open pit mining, extraction of crude bitumen and upgrading of crude bitumen into synthetic crude oil. In the Base mine (lease 17), the mining and transportation system uses draglines, bucketwheel reclaimers and belt conveyors. In the North mine (leases 17 and 22) and in the Aurora mine (leases 10, 12 and 34), truck, shovel and hydrotransport systems are used. Production from the Aurora mine commenced in 2000. The extraction facilities, which separates crude bitumen from sand, are capable of processing approximately 545,000 tons of tar sands a day, producing 110 million barrels of crude bitumen a year. This represents recovery capability of about 92 percent of the crude bitumen contained in the mined tar sands.

Crude bitumen extracted from tar sands is refined to a marketable hydrocarbon product through a combination of carbon removal in two large, high-temperature, fluid-coking vessels and by hydrogen addition in high-temperature, high-pressure, hydrocracking vessels. These processes remove carbon

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and sulfur and reformulate the crude into a low viscosity, low sulfur, high-quality synthetic crude oil product. In 2003, this upgrading process yielded 0.860 barrels of synthetic crude oil per barrel of crude bitumen. In 2003 about 55 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 45 percent was pipelined to refineries in eastern Canada and the mid-western United States. Electricity is provided to Syncrude by a 270 megawatt electricity generating plant and an 80 megawatt electricity generating plant, both located at Syncrude. The generating plants are owned by the Syncrude participants. Imperial Oil Limited's 25 percent share of net investment in plant, property and equipment, including surface mining facilities, transportation equipment and upgrading facilities was about $1.7 billion at year-end 2003.

Synthetic Crude Oil Reserves

The crude bitumen is contained within the unconsolidated sands of the McMurray Formation. Ore bodies are buried beneath 50 to 150 feet of overburden, have bitumen grades ranging from 4 to 14 weight percent and ore thickness of 115 to 160 feet. Estimates of synthetic crude oil reserves are based on detailed geological and engineering assessments of in-place crude bitumen volume, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling. Proven reserves include the operating Base and North mines and the Aurora mine. In accordance with the approved mining plan, there are an estimated 3,295 million tons of extractable tar sands in the Base and North mines, with an average bitumen grade of 10.4 weight percent. In addition, at the Aurora mine, there are an estimated 4,050 million tons of extractable tar sands at an average bitumen grade of 11.3 weight percent. After deducting royalties payable to the Province of Alberta, Imperial Oil Limited estimates that its 25 percent net share of proven reserves at year-end 2003 was equivalent to 781 million barrels of synthetic crude oil.

In 2001, the Syncrude owners endorsed a further development of the Syncrude resource in the area and expansion of the upgrading facilities. The Syncrude Aurora 2 and Upgrader Expansion 1 project adds a remote mining train and expands the central processing and upgrading plant. This expansion is under way and will lead to total production capacity of about 350 thousand barrels of synthetic crude oil per day (gross) when completed.

ExxonMobil Share of Net Proven Syncrude Reserves(1)

	Synthetic Crude Oil		
	Base Mine and North Mine	**Aurora Mine**	**Total**
		(millions of barrels)	
January 1, 2003	344	456	800
Revision of previous estimate	—	—	—
Production	(13)	(6)	(19)
December 31, 2003	331	450	781

(1) Net reserves are the company's share of reserves after deducting royalties payable to the Province of Alberta.

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Syncrude Operating Statistics (total operation)

	2003	2002	2001	2000	1999
Operating Statistics					
Total mined volume (millions of cubic yards)(1)	109.2	102.0	118.3	85.1	100.1
Mined volume to tar sands ratio(1)	1.15	1.05	1.15	0.96	0.99
Tar sands mined (millions of tons)	168.0	172.1	181.2	156.4	178.7
Average bitumen grade (weight percent)	11.0	11.2	11.0	11.0	10.8
Crude bitumen in mined tar sands (millions of tons)	18.5	19.2	19.9	17.2	19.3
Average extraction recovery (percent)	88.6	89.9	87.0	89.7	91.4
Crude bitumen production (millions of barrels)(2)	92.3	97.8	97.6	86.8	99.6
Average upgrading yield (percent)	86.0	86.3	84.5	84.3	83.9
Gross synthetic crude oil produced (millions of barrels)	78.4	84.8	82.4	73.2	83.6
ExxonMobil net share (millions of barrels)(3)	19	21	19	15	20

(1) Includes pre-stripping of mine areas and reclamation volumes.

(2) Crude bitumen production is equal to crude bitumen in mined tar sands multiplied by the average extraction recovery and the appropriate conversion factor.

(3) Reflects ExxonMobil's 25 percent interest in production less applicable royalties payable to the Province of Alberta.

Item 3. *Legal Proceedings.*

The corporation reported in its 2002 Annual Report on Form 10-K that the New York State Department of Environmental Conservation ("NYSDEC") issued 22 substantially similar Proposed Orders on Consent for 12 service stations in New York, alleging that ExxonMobil Oil Corporation ("EMOC") failed to properly register or conduct tank tightness tests in accordance with the applicable petroleum bulk storage law. The NYSDEC has agreed to dismiss 11 of the consent orders, leaving 11 consent orders with a proposed aggregate fine of $186,500 (a reduction from $347,000). EMOC received notice of three additional consent orders in which the NYSDEC alleges that EMOC failed to conduct tank tightness tests in accordance with the applicable petroleum bulk storage law: two on August 27, 2003 seeking penalties in the aggregate of $23,000, and one on October 20, 2003, seeking penalties of $14,500. The corporation is currently seeking settlement of the 14 outstanding consent orders, which relate to 13 service stations.

As reported in the corporation's Form 10-Q for the third quarter of 2002, the Texas Commission on Environmental Quality ("TCEQ") issued Notices of Enforcement to EMOC with respect to its Beaumont, Texas refinery on May 21, 2002 and on August 22, 2002. The TCEQ alleged violations of Texas Air Quality regulations relating to leak detection and repair issues. EMOC entered into a final administrative order with the TCEQ, resolving all outstanding issues in this matter, on February 21, 2004. Under the order, EMOC has paid a $75,000 penalty to the TCEQ and has paid $75,000 to Jefferson County, Texas for a supplemental environmental project.

The corporation reported in its Form 10-Q for the third quarter of 2003 that the TCEQ issued a Notice of Enforcement on June 25, 2003, alleging leak detection and repair violations and failure to submit deviation reports required by a permit. The allegations relate to Colonial Tank Farm, which is operated by EMOC's Beaumont refinery under an agreement with Colonial Pipeline. EMOC entered into an administrative order with the TCEQ on February 3, 2004 whereby EMOC has agreed to pay a civil penalty in the amount of $4,800 to resolve this matter.

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On November 12, 2003, the U.S. Environmental Protection Agency (“EPA”) issued a Notice of Violation (“NOV”) to Mobil Oil Australia Pty Ltd (“MOA”). The NOV alleges that MOA transferred for distribution on the U.S. territory of American Samoa 23 barge loads of gasoline that did not contain additives required by the Clean Air Act. These allegations were based on self-disclosure by MOA to the EPA in October 2002. The NOV also alleges, independent of MOA’s self-disclosure issues, that the 23 barge loads were not accompanied by complete product transfer documents, in violation of the Clean Air Act regulations. MOA has taken corrective action and is pursuing discussions with the EPA to ensure compliance with the additive requirements. The EPA is seeking a penalty of $298,000, but settlement discussions are underway.

On November 14, 2003, the EPA issued an NOV alleging that the corporation’s Baytown refinery released for distribution a batch of conventional gasoline with a Reid vapor pressure (RVP) in excess of the maximum RVP allowed under the Clean Air Act regulations. The corporation is pursuing discussions with the EPA in an effort to resolve this matter. The EPA is seeking a penalty of $119,380, but settlement discussions are underway.

The Office of the Attorney General for the State of New York (“State of New York”) filed a complaint on April 9, 2002 in a case captioned “State of New York v. Mobil Business Resources Corporation f/k/a Mobil Administration Services, Inc. and Mobil Oil Corporation, f/k/a Socony Vacuum Oil Company.” The State of New York alleges that petroleum was discharged from an underground storage tank at a corporation-owned Mobil branded service station in Mamaroneck, New York, and that the corporation failed to remediate and report the alleged spill, in violation of the New York State Navigation Law. Pursuant to communication to ExxonMobil Oil Corporation in December 2003, the State of New York is seeking penalties of $550,000 as well as compensatory damages. The corporation has filed an answer to the complaint and settlement discussions are underway.

Refer to the relevant portions of Note 17 on page 62 of the Financial Section of this report for additional information on legal proceedings.

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

None.

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Executive Officers of the Registrant [pursuant to Instruction 3 to Regulation S-K, Item 401(b)].

Name	Age as of March 15, 2004	Title (Held Office Since)
L. R. Raymond	65	Chairman of the Board (1993)
R. W. Tillerson	51	President (2004)
H. J. Longwell	62	Executive Vice President (2001)
E. G. Galante	53	Senior Vice President (2001)
H. R. Cramer	53	Vice President (1999)
P. J. Dingle	55	Vice President (2003)
M. E. Foster	60	President, ExxonMobil Development Company (1999)
D. D. Humphreys	56	Vice President and Controller (1997)
G. L. Kohlenberger	51	Vice President (2002)
C. W. Matthews	59	Vice President and General Counsel (1995)
S. R. McGill	61	Vice President (1998)
P. T. Mulva	52	Vice President — Investor Relations and Secretary (2002)
F. A. Risch	61	Vice President and Treasurer (1999)
D. S. Sanders	64	Vice President (1999)
J. S. Simon	60	Vice President (1999)
P. E. Sullivan	60	Vice President and General Tax Counsel (1995)
J. L. Thompson	64	Vice President (1991)

For at least the past five years, Messrs. Humphreys, Longwell, Matthews, McGill, Raymond, Risch, Sanders, Sullivan and Thompson have been employed as executives of the registrant. Mr. Tillerson was a Senior Vice President before becoming President.

The following executive officers of the registrant have also served as executives of the subsidiaries, affiliates or divisions of the registrant shown opposite their names during the five years preceding December 31, 2003.

Esso Malaysia Berhad	Dingle
Esso Production Malaysia Inc.	Dingle
Esso (Thailand) Public Company Limited	Galante
Exxon Company, International	Simon
Exxon Neftegas Limited	Tillerson
Exxon Upstream Development Company	Foster
Exxon Ventures (CIS) Inc.	Tillerson
ExxonMobil Chemical Company	Galante
ExxonMobil Development Company	Tillerson
ExxonMobil Fuels Marketing Company	Cramer
ExxonMobil Gas & Power Marketing Company	Dingle
ExxonMobil Global Services Company	Kohlenberger
ExxonMobil Lubricants & Petroleum Specialties Company	Kohlenberger
ExxonMobil Refining & Supply Company	Simon
Imperial Oil Limited	Mulva
Mobil Business Resources Corporation	Kohlenberger
Mobil Corporation	Cramer

Officers are generally elected by the Board of Directors at its meeting on the day of each annual election of directors, with each such officer serving until a successor has been elected and qualified.

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PART II

Item 5. *Market for Registrant's Common Equity and Related Stockholder Matters.*

Reference is made to the quarterly information which appears on page 69 of the Financial Section of this report.

In accordance with the registrant's 1997 Nonemployee Director Restricted Stock Plan, as amended, each incumbent nonemployee director (10 persons) was granted 2,400 shares of restricted stock on January 1, 2004. These grants are exempt from registration under bonus stock interpretations such as the "no-action" letter to *Pacific Telesis Group* (June 30, 1992).

Item 6. *Selected Financial Data.*

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(millions of dollars, except per share amounts)				
Sales and other operating revenue(1)	$237,054	$200,949	$208,715	$227,596	$181,759
(1) Excise taxes included	$ 23,855	$ 22,040	$ 21,907	$ 22,356	$ 21,646
Net income					
Income from continuing operations	$ 20,960	$ 11,011	$ 15,003	$ 15,806	$ 7,845
Discontinued operations, net of income tax	—	449	102	184	65
Extraordinary gain, net of income tax	—	—	215	1,730	—
Cumulative effect of accounting change, net of income tax	550	—	—	—	—
Net income	$ 21,510	$ 11,460	$ 15,320	$ 17,720	$ 7,910
Net income per common share					
Income from continuing operations	$ 3.16	$ 1.62	$ 2.19	$ 2.27	$ 1.13
Discontinued operations, net of income tax	—	0.07	0.01	0.03	0.01
Extraordinary gain, net of income tax	—	—	0.03	0.25	—
Cumulative effect of accounting change, net of income tax	0.08	—	—	—	—
Net income	$ 3.24	$ 1.69	$ 2.23	$ 2.55	$ 1.14
Net income per common share - assuming dilution					
Income from continuing operations	$ 3.15	$ 1.61	$ 2.17	$ 2.24	$ 1.11
Discontinued operations, net of income tax	—	0.07	0.01	0.03	0.01
Extraordinary gain, net of income tax	—	—	0.03	0.25	—
Cumulative effect of accounting change, net of income tax	0.08	—	—	—	—
Net income	$ 3.23	$ 1.68	$ 2.21	$ 2.52	$ 1.12
Cash dividends per common share	$ 0.980	$ 0.920	$ 0.910	$ 0.880	$ 0.844
Total assets	$174,278	$152,644	$143,174	$149,000	$144,521
Long-term debt	$ 4,756	$ 6,655	$ 7,099	$ 7,280	$ 8,402

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

Reference is made to the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 28 of the Financial Section of this report.

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

Reference is made to the section entitled "Market Risks, Inflation and Other Uncertainties" beginning on page 37, excluding the part entitled "Inflation and Other Uncertainties," of the Financial Section of this report. All statements other than historical information incorporated in this Item 7A are forward-looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this report.

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

Reference is made to the following in the Financial Section of this report:

- Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP dated February 25, 2004, beginning on page 42 with the section entitled "Report of Independent Auditors" and continuing to page 68;
- Quarterly Information appearing on page 69;
- Supplemental Information on Oil and Gas Exploration and Production Activities appearing on pages 70 to 74; and
- Frequently Used Terms on pages 26 and 27.

Financial Statement Schedules have been omitted because they are not applicable or the required information is shown in the consolidated financial statements or notes thereto.

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

None.

Item 9A. ***Controls and Procedures*.**

As indicated in the certifications in Exhibit 31 of this report, the corporation's principal executive officer, principal accounting officer and principal financial officer have evaluated the corporation's disclosure controls and procedures as of December 31, 2003. Based on that evaluation, these officers have concluded that the corporation's disclosure controls and procedures are effective for the purpose of ensuring that material information required to be in this annual report is made known to them by others on a timely basis. There have not been changes in the corporation's internal control over financial reporting that occurred during the corporation's last fiscal quarter that have materially affected, or are reasonably likely to materially affect the corporation's internal control over financial reporting.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

Incorporated by reference to the following from the registrant's definitive proxy statement for the 2004 annual meeting of shareholders (the "2004 Proxy Statement"):

- The section entitled "Election of Directors";
- The portion entitled "Section 16(a) Beneficial Ownership Reporting Compliance" of the section entitled "Executive Compensation Tables";
- The portion entitled "Code of Ethics and Business Conduct" of the section entitled "Corporate Governance"; and
- The "Audit Committee" portion of the section entitled "Board Committees".

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Item 11. ***Executive Compensation.***

Incorporated by reference to the section entitled "Director Compensation" and the section entitled "Executive Compensation Tables" of the registrant's 2004 Proxy Statement.

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

Incorporated by reference to the section entitled "Director and Executive Officer Stock Ownership" and the portion entitled "Equity Compensation Plan Information" of the section entitled "Executive Compensation Tables" of the registrant's 2004 Proxy Statement.

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

Incorporated by reference to the portion entitled "Director Relationships" of the section entitled "Election of Directors" of the registrant's 2004 Proxy Statement.

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

Incorporated by reference to the section entitled "Ratification of Independent Auditors" of the registrant's 2004 Proxy Statement.

PART IV

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

(a) (1) and (2) Financial Statements:
See Table of Contents on page 23 of the Financial Section of this report.

(a) (3) Exhibits:
See Index to Exhibits on page 78 of this report.

(b) Reports on Form 8-K.

On October 30, 2003, the registrant filed a Current Report on Form 8-K furnishing under Item 9, and also pursuant to Item 12, its News Release, dated October 30, 2003, announcing third quarter results and the information in the related 3Q03 Investor Relations Data Summary.

On November 14, 2003, the registrant filed a Current Report on Form 8-K under Item 5, about a court ruling related to the Mobile Bay royalties dispute in Alabama.

On November 20, 2003, the registrant filed a Current Report on Form 8-K under Item 5, about the resolution of a tax dispute with the Internal Revenue Service.

On January 13, 2004, the registrant filed a Current Report on Form 8-K furnishing under Item 9, information about a presentation discussing upstream development activities and initiatives.

On January 29, 2004, the registrant filed a Current Report on Form 8-K furnishing under Item 9, and also pursuant to Item 12, its News Release, dated January 29, 2004, announcing fourth quarter results and the information in the related 4Q03 Investor Relations Data Summary.

On January 29, 2004, the registrant filed a Current Report on Form 8-K under Item 5, about a court ruling related to the Exxon Valdez accident.

On February 18, 2004, the registrant filed a Current Report on Form 8-K furnishing under Item 9, and also pursuant to Item 12, its News Release, dated February 18, 2004, announcing 2003 additions to worldwide proved oil and gas reserves and the related reserve replacement percentage.

On February 27, 2004, the registrant filed a Current Report on Form 8-K furnishing under Item 9 information about the election of Rex Tillerson as president and a director of Exxon Mobil Corporation.

Reports listed above as "furnished" under Item 9 and Item 12 are not deemed "filed" with the SEC and are not incorporated by reference herein or in any other SEC filings.

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FINANCIAL SECTION

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BUSINESS PROFILE

Financial	Earnings After Income Taxes 2003	Earnings After Income Taxes 2002	Average Capital Employed 2003	Average Capital Employed 2002	Return on Average Capital Employed 2003	Return on Average Capital Employed 2002	Capital and Exploration Expenditures 2003	Capital and Exploration Expenditures 2002
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	$ 3,905	$ 2,524	$13,508	$13,264	28.9	19.0	$ 2,125	$ 2,357
Non-U.S.	10,597	7,074	34,164	29,800	31.0	23.7	9,863	8,037
Total	$14,502	$ 9,598	$47,672	$43,064	30.4	22.3	$11,988	$10,394
Downstream								
United States	$ 1,348	$ 693	$ 8,090	$ 8,060	16.7	8.6	$ 1,244	$ 980
Non-U.S.	2,168	607	18,875	17,985	11.5	3.4	1,537	1,470
Total	$ 3,516	$ 1,300	$26,965	$26,045	13.0	5.0	$ 2,781	$ 2,450
Chemicals								
United States	$ 381	$ 384	$ 5,194	$ 5,235	7.3	7.3	$ 333	$ 575
Non-U.S.	1,051	446	8,905	8,410	11.8	5.3	359	379
Total	$ 1,432	$ 830	$14,099	$13,645	10.2	6.1	$ 692	$ 954
Corporate and financing	1,510	(442)	6,637	4,878	—	—	64	77
Merger related expenses	—	(275)	—	—	—	—	—	—
Discontinued operations	—	449	—	710	—	63.2	—	80
Accounting change	550	—	—	—	—	—	—	—
Total	$21,510	$11,460	$95,373	$88,342	20.9	13.5	$15,525	$13,955

See Frequently Used Terms on pages 26 and 27 for a definition and calculation of capital employed and return on average capital employed.

Operating	2003	2002
	(thousands of barrels daily)	
Net liquids production		
United States	610	681
Non-U.S.	1,906	1,815
Total	2,516	2,496
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	2,246	2,375
Non-U.S.	7,873	8,077
Total	10,119	10,452
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production [(1)]	4,203	4,238

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

	(thousands of barrels daily)	
Petroleum product sales		
United States	2,729	2,731
Non-U.S.	5,228	5,026
Total	7,957	7,757
	(thousands of barrels daily)	
Refinery throughput		
United States	1,806	1,834
Non-U.S.	3,704	3,609
Total	5,510	5,443
	(thousands of metric tons)	
Chemical prime product sales		
United States	10,740	11,386
Non-U.S.	15,827	15,220
Total	26,567	26,606

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FINANCIAL SUMMARY

	2003	2002	2001	2000	1999
	(millions of dollars, except per share amounts)				
Sales and other operating revenue [(1)]					
Upstream	$ 21,330	$ 16,484	$ 18,567	$ 21,509	$ 14,565
Downstream	195,511	168,032	174,185	188,563	153,345
Chemicals	20,190	16,408	15,943	17,501	13,777
Other	23	25	20	23	72
Total	$237,054	$200,949	$208,715	$227,596	$181,759
Earnings					
Upstream	$ 14,502	$ 9,598	$ 10,736	$ 12,685	$ 6,244
Downstream	3,516	1,300	4,227	3,418	1,227
Chemicals	1,432	830	707	1,161	1,354
Corporate and financing	1,510	(442)	(142)	(538)	(511)
Merger related expenses	—	(275)	(525)	(920)	(469)
Income from continuing operations	$ 20,960	$ 11,011	$ 15,003	$ 15,806	$ 7,845
Discontinued operations	—	449	102	184	65
Extraordinary gain	—	—	215	1,730	—
Accounting change	550	—	—	—	—
Net income	$ 21,510	$ 11,460	$ 15,320	$ 17,720	$ 7,910
Net income per common share	$ 3.24	$ 1.69	$ 2.23	$ 2.55	$ 1.14
Net income per common share – assuming dilution	$ 3.23	$ 1.68	$ 2.21	$ 2.52	$ 1.12
Cash dividends per common share	$ 0.980	$ 0.920	$ 0.910	$ 0.880	$ 0.844
Net income to average shareholders’ equity (percent)	26.2	15.5	21.3	26.4	12.6
Net income to total revenues and other income (percent)	8.7	5.6	7.2	7.6	4.3
Working capital	$ 7,574	$ 5,116	$ 5,567	$ 2,208	$ (7,592)
Ratio of current assets to current liabilities	1.20	1.15	1.18	1.06	0.80
Additions to property, plant and equipment	$ 12,859	$ 11,437	$ 9,989	$ 8,446	$ 10,849
Property, plant and equipment, less allowances	$104,965	$ 94,940	$ 89,602	$ 89,829	$ 94,043
Total assets	$174,278	$152,644	$143,174	$149,000	$144,521
Exploration expenses, including dry holes	$ 1,010	$ 920	$ 1,175	$ 936	$ 1,246
Research and development costs	$ 618	$ 631	$ 603	$ 564	$ 630
Long-term debt	$ 4,756	$ 6,655	$ 7,099	$ 7,280	$ 8,402
Total debt	$ 9,545	$ 10,748	$ 10,802	$ 13,441	$ 18,972
Fixed charge coverage ratio (times)	30.8	13.8	17.7	15.6	6.6
Debt to capital (percent)	9.3	12.2	12.4	15.4	22.0
Net debt to capital (percent)	(1.2)	4.4	5.3	7.9	20.4
Shareholders’ equity at year-end	$ 89,915	$ 74,597	$ 73,161	$ 70,757	$ 63,466
Shareholders’ equity per common share	$ 13.69	$ 11.13	$ 10.74	$ 10.21	$ 9.13
Average number of common shares outstanding (millions)	6,634	6,753	6,868	6,953	6,906
Number of regular employees at year-end (thousands) [(2)]	88.3	92.5	97.9	99.6	106.9
CORS employees not included above (thousands) [(3)]	17.4	16.8	19.9	18.7	15.7

(1) *Sales and other operating revenue includes excise taxes of $23,855 million for 2003, $22,040 million for 2002, $21,907 million for 2001, $22,356 million for 2000 and $21,646 million for 1999.*

(2) *Regular employees are defined as active executive, management, professional, technical and wage employees who work full-time or part-time for the company and are covered by the company's benefit plans and programs.*

(3) *CORS employees are employees of company-operated retail sites.*

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FREQUENTLY USED TERMS

Listed below are definitions of several of ExxonMobil's key business financial performance measures. These definitions are provided to facilitate understanding of the terms and their calculation.

CASH FLOW FROM OPERATIONS AND ASSET SALES

Cash flow from operations and asset sales is the sum of the net cash provided by operating activities and proceeds from sales of subsidiaries, investments and property, plant and equipment from the Consolidated Statement of Cash Flows. This cash flow is the total sources of cash from both operating the company's assets and from the divesting of assets. The corporation employs a long-standing disciplined regular review process to ensure that all assets are contributing to the company's strategic and financial objectives. Assets are divested when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature of this activity, we believe it is useful for investors to consider sales proceeds together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash flow from operations and asset sales	**2003**	**2002**	**2001**
		(millions of dollars)	
Net cash provided by operating activities	$28,498	$21,268	$22,889
Sales of subsidiaries, investments and property, plant and equipment	2,290	2,793	1,078
Cash flow from operations and asset sales	$30,788	$24,061	$23,967

CAPITAL EMPLOYED

Capital employed is a measure of net investment. When viewed from the perspective of how the capital is used by the businesses, it includes ExxonMobil's net share of property, plant and equipment and other assets less liabilities, excluding both short-term and long-term debt. When viewed from the perspective of the sources of capital employed in total for the corporation, it includes ExxonMobil's share of total debt and shareholders' equity. Both of these views include ExxonMobil's share of amounts applicable to equity companies, which the corporation believes should be included to provide a more comprehensive measure of capital employed.

Capital employed	**2003**	**2002**	**2001**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	$174,278	$152,644	$143,174
Less liabilities and minority share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(33,597)	(29,082)	(26,411)
Total long-term liabilities excluding long-term debt and equity of minority and preferred shareholders in affiliated companies	(37,839)	(35,449)	(29,975)
Minority share of assets and liabilities	(4,945)	(4,210)	(3,985)
Add ExxonMobil share of debt-financed equity company net assets	4,151	4,795	5,182
Total capital employed	$102,048	$ 88,698	$ 87,985
Total corporate sources: debt and equity perspective			
Notes and loans payable	$ 4,789	$ 4,093	$ 3,703
Long-term debt	4,756	6,655	7,099
Shareholders' equity	89,915	74,597	73,161
Less minority share of total debt	(1,563)	(1,442)	(1,160)
Add ExxonMobil share of equity company debt	4,151	4,795	5,182
Total capital employed	$102,048	$ 88,698	$ 87,985

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RETURN ON AVERAGE CAPITAL EMPLOYED

Return on average capital employed (ROCE) is a performance measure ratio. From the perspective of the business segments, ROCE is annual business segment earnings divided by average business segment capital employed (average of beginning and end-of-year amounts). These segment earnings include ExxonMobil's share of segment earnings of equity companies, consistent with our capital employed definition, and exclude the cost of financing. The corporation's total ROCE is net income excluding the after-tax cost of financing, divided by total corporate average capital employed. The corporation has consistently applied its ROCE definition for many years and views it as the best measure of historical capital productivity in our capital intensive long-term industry, both to evaluate management's performance and to demonstrate to shareholders that capital has been used wisely over the long term. Additional measures, which tend to be more cash flow based, are used for future investment decisions.

Return on average capital employed	**2003**	**2002**	**2001**
		(millions of dollars)	
Net income	$21,510	$11,460	$15,320
Financing costs (after tax)			
Third-party debt	(69)	(81)	(96)
ExxonMobil share of equity companies	(172)	(227)	(229)
All other financing costs – net [(1)]	1,775	(127)	(25)
Total financing costs	1,534	(435)	(350)
Earnings excluding financing costs	$19,976	$11,895	$15,670
Average capital employed	$95,373	$88,342	$88,000
Return on average capital employed – corporate total	20.9%	13.5%	17.8%

(1) "All other financing costs – net" in 2003 includes interest income (after tax) associated with the settlement of a U.S. tax dispute.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FUNCTIONAL EARNINGS

	2003	2002	2001
	(millions of dollars, except per share amounts)		
Net income (U.S. GAAP)			
Upstream			
United States	$ 3,905	$ 2,524	$ 3,933
Non-U.S.	10,597	7,074	6,803
Downstream			
United States	1,348	693	1,924
Non-U.S.	2,168	607	2,303
Chemicals			
United States	381	384	298
Non-U.S.	1,051	446	409
Corporate and financing	1,510	(442)	(142)
Merger related expenses	—	(275)	(525)
Income from continuing operations	$20,960	$11,011	$15,003
Discontinued operations	—	449	102
Extraordinary gain	—	—	215
Accounting change	550	—	—
Net income (U.S. GAAP)	$21,510	$11,460	$15,320
Net income per common share (U.S. GAAP)	$ 3.24	$ 1.69	$ 2.23
Net income per common share – assuming dilution (U.S. GAAP)	$ 3.23	$ 1.68	$ 2.21
Special items included in net income			
Non-U.S. upstream			
Gain on transfer of Ruhrgas shares	$ 1,700	$ —	$ —
U.K. deferred income tax adjustment	$ —	$ (215)	$ —
Corporate and financing			
U.S. tax settlement	$ 2,230	$ —	$ —

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FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future results, including production growth; financing sources; the resolution of contingencies; the effect of changes in prices; interest rates and other market conditions; and environmental and capital expenditures could differ materially depending on a number of factors, such as the outcome of commercial negotiations; changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; and other factors discussed herein and under the caption "Factors Affecting Future Results" in Item 1 of ExxonMobil's 2003 Form 10-K.

OVERVIEW

The following discussion and analysis of ExxonMobil's financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Exxon Mobil Corporation. The corporation's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The corporation's business model involves the production (or purchase), manufacture and sale of physical products, and all commercial activities are directly in support of the underlying physical movement of goods.

This straightforward approach extends to the financing of the business. In evaluating business or investment opportunities, the corporation views as economically equivalent any debt obligation, whether included on the face of the consolidated balance sheet, or disclosed as other debt-like obligations in notes to the financial statements, such as ExxonMobil's share of equity company debt and noncancelable, long-term operating leases. This consistent, conservative approach to financing the capital intensive needs of the corporation has helped ExxonMobil to sustain the "triple-A" status of its long-term debt securities for 85 years.

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well positioned to participate in substantial investments to develop new energy supplies. While commodity prices remain volatile on a short-term basis depending on supply and demand, ExxonMobil's investment decisions are based on long-term outlooks, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Annual volumes are based on individual field production profiles which are also updated annually. Prices for natural gas and other products sold under contract are based on corporate plan assumptions developed annually by major region/contract and used for investment evaluation purposes. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects. ExxonMobil views return on capital employed as the best measure of historical capital productivity.

BUSINESS ENVIRONMENT AND OUTLOOK

Upstream

Economic growth is expected to remain the primary driver of energy demand. The corporation expects the global economy to grow at an average rate of about 3 percent per year through 2020. World energy demand should grow by about 2 percent per year, and hydrocarbons — oil, gas and coal — are expected to still account for about 80 percent of energy supply by 2020.

Natural gas is expected to be the fastest growing primary energy source, capturing about one-third of all incremental energy growth and approaching one-quarter of global energy supplies. Natural gas remains the primary choice of fuel to meet worldwide electricity demand, which is expected to grow by about 3 percent per year. An area of significant interest is development of a worldwide liquefied natural gas (LNG) market. The corporation expects the LNG market to quadruple by 2020, accounting for about 13 percent of total world gas demand. During the same period, ExxonMobil's LNG production is expected to outpace market growth and increase by a factor of six. With equity positions in many of the largest remote gas accumulations in the world, the corporation is positioned to benefit from its technology advances in gas liquefaction, transportation and regasification that enable distant gas supplies to reach markets economically.

Meeting growing oil and gas demand will be a challenge, but new technologies will continue to extend the recoverable hydrocarbon resource. The costs to develop these resources are large. According to the International Energy Agency's 2003 report on the world energy investment outlook, the investment required to meet total oil and gas energy demands through 2030 will average about $200 billion per year.

ExxonMobil has a large and diverse global portfolio of both developed and undeveloped acreage which helps mitigate the overall political and technical risk of the corporation's upstream segment. As these resources are converted into production volumes, the corporation expects a shift in the geographic mix of production volumes between now and 2010. For example, oil and natural gas output from Africa, the Caspian region, the Middle East and Russia will more than double during the next seven years based on current capital project execution plans. Currently these growth areas account for less than 20 percent of the corporation’s production. By the end of the decade they are expected to generate about 40 percent of total volumes. Production from established areas, including Europe and North America, will decline as a percentage of the corporation’s total production but still is expected to represent over half of 2010 volumes.

In addition to a changing geographic mix, there will also be a change in the type of opportunities from which volumes are produced. Production from non-conventional sources using arctic technology, deepwater drilling and production systems, heavy oil recovery processes and LNG is expected to grow from 20 percent to 40 percent of the corporation’s output between now and 2010.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Downstream

The downstream continues to experience significant volatility in industry margins. Refining margins are a function of the difference between what a refinery pays for its raw materials (primarily crude oil) and the market prices for the range of products produced (primarily gasoline, heating oil, jet fuel and fuel oil). Crude oil and many products are widely traded with published prices, including those quoted on multiple exchanges around the world (e.g., New York Mercantile Exchange and International Petroleum Exchange). Prices for these commodities (crude and various products) are determined by the marketplace and are impacted by many industry factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, seasonality and weather. These prices and factors are continuously monitored and input to decisions about which raw materials to buy, facilities to operate and products to make. However, there are no reliable indicators of future market factors that accurately predict changes in margins from period to period.

The objectives of ExxonMobil's downstream strategies are to position the corporation to be the industry leader and outperform competition under a variety of market conditions. These strategies include maintaining best-in-class operations in all respects, maximizing value from leading-edge technology, capitalizing on integration with other ExxonMobil businesses, and providing quality, valued products and services to the corporation's customers. ExxonMobil has an ownership interest in 45 refineries, located in 25 countries, with distillation capacity of 6.3 million barrels per day and lubricant basestock manufacturing capacity of about 150 thousand barrels per day. ExxonMobil's fuels marketing business portfolio includes operations in over 100 countries on six continents, serving a globally diverse customer base.

Chemicals

Worldwide industry chemical demand grew 3 percent during 2003, primarily driven by demand growth in Asia. Demand in the established North American markets remained relatively flat, with industrial production lagging the economic recovery. European demand grew marginally. Growth in Asia slowed at the beginning of the year and recovered sharply during the second half. Challenged by high energy costs and volatile feedstock prices, industry margins improved slightly. ExxonMobil's portfolio includes many of the largest-volume and highest-growth petrochemicals in the global economy. In addition to being a worldwide supplier of primary petrochemical products, the corporation also has a diverse portfolio of less-cyclical business lines. The corporation's competitive advantages are achieved through combinations of low cost feedstocks, proprietary technology, operational excellence, product application expertise and synergies between businesses.

REVIEW OF 2003 AND 2002 RESULTS

	2003	**2002**	**2001**
		(millions of dollars)	
Income from Continuing Operations	$20,960	$11,011	$15,003
Discontinued operations	—	449	102
Extraordinary gain	—	—	215
Accounting change	550	—	—
Net Income (U.S. GAAP)	$21,510	$11,460	$15,320

2003

Net income in 2003 was $21,510 million, an increase of $10,050 million from 2002. Excluding a $550 million positive impact for the required adoption of FAS 143 relating to accounting for asset retirement obligations, income from continuing operations was $20,960 million. 2003 net income also included one-time special items of $2,230 million relating to the positive settlement of a long-running U.S. tax dispute and $1,700 million from a gain on the transfer of shares in Ruhrgas AG, a German gas transmission company. Revenues and other income for 2003 totaled $247 billion, up 21 percent from 2002. Interest expense in 2003 was $207 million compared to $398 million in 2002, reflecting lower debt levels and non-debt related items.

Total assets at December 31, 2003 of $174 billion increased by approximately $21.6 billion from 2002, reflecting the corporation's active investment program and the effect of the weaker U.S. dollar.

2002

Net income in 2002 was $11,460 million, a decrease of $3,860 million from 2001. Excluding earnings from discontinued operations of

$449 million, income from continuing operations in 2002 was $11,011 million. Excluding earnings of $102 million from discontinued operations and an extraordinary gain of $215 million, income from continuing operations in 2001 was $15,003 million. Revenues and other income for 2002 totaled $205 billion, down 4 percent from 2001. Interest expense in 2002 was $398 million compared to $293 million in 2001 primarily reflecting non-debt related items.

Total assets at December 31, 2002 of $153 billion increased by approximately $9.5 billion from 2001 reflecting the corporation's active investment program and the effect of the weaker U.S. dollar.

Upstream

	2003	**2002**	**2001**
		(millions of dollars)	
Upstream			
United States	$ 3,905	$2,524	$ 3,933
Non-U.S.	10,597	7,074	6,803
Total	$14,502	$9,598	$10,736

2003

Upstream earnings totaled $14,502 million, including $1,700 million from a gain on the transfer of shares in Ruhrgas AG. Absent this, upstream earnings increased by $3,204 million from 2002 due to higher liquids and natural gas realizations. Oil-equivalent production was up 1 percent versus 2002 excluding the effects of operational outages in the North Sea and West Africa, the national strike in Venezuela and price-related entitlement effects. Total actual oil-equivalent production was down 1 percent. Liquids production of 2,516 kbd (thousands of barrels daily) increased 20 kbd from 2002. Production increases from new projects in West Africa, Norway and Canada, and lower OPEC-driven quota constraints, were partly offset by natural field decline, operational problems in the North Sea and West Africa, and the impact of the national strike in Venezuela. Natural gas production of 10,119 mcfd (millions of cubic feet daily) in 2003 compared with 10,452 mcfd in 2002. Higher demand in the first half of the year in Europe and contributions from new projects and work programs were more than offset by natural field decline, reduced entitlements and operational

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outages in the North Sea. Improved earnings from both U.S. and non-U.S. upstream operations were driven by higher liquids and natural gas realizations. Earnings from U.S. upstream operations for 2003 were $3,905 million, an increase of $1,381 million. Earnings outside the U.S. for 2003, including $1,700 million from a gain on the transfer of shares in Ruhrgas AG, were $10,597 million. Earnings outside the U.S. for 2002, including a special charge of $215 million relating to a United Kingdom tax rate change, were $7,074 million.

2002

Upstream earnings totaled $9,598 million, including a special charge of $215 million relating to the impact on deferred taxes from the United Kingdom supplementary tax enacted in 2002. Absent this, upstream earnings of $9,813 million decreased $923 million primarily due to lower natural gas realizations, particularly in North America, where prices reached historical highs at the beginning of 2001. Higher crude oil realizations partly offset declines in natural gas prices. Oil-equivalent production was up 1 percent versus 2001 excluding the impact of OPEC quota restrictions. Total actual oil-equivalent production was flat as the resumption of full production at Arun and contributions from new projects and work programs offset natural field declines and OPEC quota restrictions. Liquids production of 2,496 kbd decreased 46 kbd from 2001. Production increases from new projects in Angola, Canada, Malaysia and Venezuela offset natural field declines in mature areas. OPEC quota restrictions increased in 2002. Excluding the effect of these restrictions, liquids production was flat with 2001. Worldwide natural gas production of 10,452 mcfd in 2002 compared with 10,279 mcfd in 2001. Improvements in Asia-Pacific volumes, mainly from the return to full production levels at the Arun field in Indonesia following curtailments due to security concerns in 2001, more than offset lower weather-related demand in Europe and natural field decline in the U.S. Weather-related demand in Europe reduced total gas volumes by about 1 percent. Earnings from U.S. upstream operations for 2002 were $2,524 million, a decrease of $1,409 million due to lower gas realizations and reduced gas and liquids volumes. Including the $215 million special charge relating to the United Kingdom tax rate change reported in 2002, earnings outside the U.S. were $7,074 million, $271 million higher than 2001 with higher crude oil realizations and increased gas and liquids volumes partly offset by lower gas realizations.

Downstream

	2003	2002	2001
	(millions of dollars)		
Downstream			
United States	$1,348	$ 693	$1,924
Non-U.S.	2,168	607	2,303
Total	$3,516	$1,300	$4,227

2003

Downstream earnings of $3,516 million increased by $2,216 million from 2002, reflecting higher worldwide refining and marketing margins. Earnings also benefited from a planned reduction in inventories as a result of optimizing operations around the world. Petroleum product sales of 7,957 kbd were 200 kbd higher than 2002, largely related to increased refinery runs due to strong margins and higher demand for distillates. Refinery throughput was 5,510 kbd compared with 5,443 kbd in 2002. U.S. downstream earnings of $1,348 million increased by $655 million, reflecting higher refining and marketing margins partly offset by increased refinery turnaround activity in the year. Non-U.S. downstream earnings of $2,168 million were $1,561 million higher than 2002 due to higher refining and marketing margins, increased refinery runs and positive inventory impacts.

2002

Downstream earnings of $1,300 million decreased by $2,927 million from a record 2001, reflecting significantly lower refining margins in most geographical areas, and further weakness in marketing margins. Improved refining operations and lower expenses provided a partial offset to the margin decline. Earnings also benefited from a planned reduction in inventories as a result of optimizing operations around the world. Petroleum product sales of 7,757 kbd decreased 214 kbd from 2001, largely related to reduced refinery runs due to weak margins and lower demand for distillates and aviation fuels. Refinery throughput was 5,443 kbd compared with 5,542 kbd in 2001. U.S. downstream earnings were $693 million, down $1,231 million due to weaker refining margins. Earnings outside the U.S. of $607 million were $1,696 million lower than 2001 due to lower refining and marketing margins.

Chemicals

	2003	2002	2001
	(millions of dollars)		

Chemicals			
United States	$ 381	$384	$298
Non-U.S.	1,051	446	409
Total	$1,432	$830	$707

2003

Chemicals earnings of $1,432 million were up $602 million from 2002. Earnings benefited from improved worldwide margins and favorable foreign exchange effects. Prime product sales of 26,567 kt (thousands of metric tons) were in line with record sales of 26,606 kt in 2002. Prime product sales are total chemical product sales including ExxonMobil's share of equity-company volumes and finished-product transfers to the downstream business. Carbon black oil volumes are excluded. U.S. chemicals earnings of $381 million were $3 million lower than 2002 with higher margins offset by lower volumes on weaker demand. Non-U.S. chemicals earnings of $1,051 million were $605 million higher than 2002 due to higher margins, strong demand in Asia and favorable foreign exchange effects.

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2002

Chemicals earnings of $830 million for 2002 were $123 million higher than 2001. Earnings benefited from record prime product sales volumes of 26,606 kt which were 3 percent above 2001, reflecting capacity additions in Singapore and Saudi Arabia. Worldwide chemicals margins remained weak during 2002.

All Other Segments

	2003	2002	2001
		(millions of dollars)	
All Other Segments			
Corporate and financing	$1,510	$(442)	$(142)
Merger expenses	—	(275)	(525)
Discontinued operations	—	449	102
Extraordinary gain	—	—	215
Accounting change	550	—	—
Total	$2,060	$(268)	$(350)

2003

All other segments totaled a gain of $2,060 million in 2003 compared to a loss of $268 million in 2002.

Corporate and financing in 2003, including $2,230 million relating to the settlement of a long-running U.S. tax dispute, contributed $1,510 million to earnings. Excluding this settlement, corporate and financing expenses increased by $278 million mainly due to higher U.S. pension expense.

Merger related activities were completed in 2002 and net income included $275 million of merger related expenses. Net income in 2002 also included discontinued operations earnings of $449 million, including a gain associated with the sale of the Chilean copper business.

2002

All other segments represented a loss of $268 million in 2002 compared to a loss of $350 million in 2001.

Corporate and financing expenses increased $300 million to $442 million, primarily due to higher U.S. pension expense, reflecting lower returns on fund assets and the effects of lower interest rates and lower cash balances on interest income. Merger related expenses decreased $250 million to $275 million reflecting the completion of merger related activities at year-end 2002. Discontinued operations earnings of $449 million, including a gain associated with the sale of the Chilean copper business, compared to $102 million in 2001.

Accounting Change

As of January 1, 2003, the corporation adopted Financial Accounting Standards Board Statement of Financial Accounting Standards No. 143 (FAS 143), "Accounting for Asset Retirement Obligations." The primary impact of FAS 143 is to change the method of accruing for upstream site restoration costs. Asset retirement obligations are not recorded for downstream and chemical facilities because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

Upstream costs were previously accrued ratably over the productive lives of the assets in accordance with Statement of Financial Accounting Standards No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies." At the end of 2002, the cumulative amount accrued under FAS 19 was approximately $3.5 billion. Under FAS 143, the fair values of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically at the time the assets are installed. Amounts recorded for the related assets will be increased by the amount of these obligations. Over time the liabilities will be accreted for the change in their present value and the initial capitalized costs will be depreciated over the useful lives of the related assets.

The cumulative adjustment for the change in accounting principle reported in the first quarter of 2003 was after-tax income of $550 million (net of $442 million of income tax effects, including ExxonMobil's share of related equity company income taxes of $51 million), or $0.08 per common share. The effect of this accounting change on the balance sheet was a $0.3 billion increase to property, plant and equipment, a $0.6 billion reduction to the accrued liability and a $0.4 billion increase in deferred income tax liabilities.

This adjustment is due to the difference in the method of accruing site restoration costs under FAS 143 compared with the method required by FAS 19, the accounting standard that the corporation has been required to follow since 1978. Under FAS 19, site restoration costs were accrued on a unit-of-production basis of accounting as the oil and gas was produced. The FAS 19 method matched the accruals with the revenues generated from production and resulted in most of the costs being accrued early in field life, when production is at the highest level. Because FAS 143 requires accretion of the liability as a result of the passage of time using an interest method of allocation, the majority of the costs will be accrued toward the end of field life, when production is at the lowest level. The cumulative income adjustment described above resulted from reversing the higher liability accumulated under FAS 19 in order to adjust it to the lower present value amount resulting from transition to FAS 143. This amount being reversed in transition, which was previously charged to operating earnings under FAS 19, will again be charged to those earnings under FAS 143 in future years.

If FAS 143 had been in effect in 2002, net income that would have been reported would not have been materially different from the net income that was reported under FAS 19. The effect of FAS 143 on net income in the current year period is also not material.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2003	2002
	(millions of dollars)	
Net cash provided by/(used in)		
Operating activities	$ 28,498	$ 21,268
Investing activities	(10,842)	(9,758)
Financing activities	(14,763)	(11,353)
Effect of exchange rate changes	504	525
Increase/(decrease) in cash and cash equivalents	$ 3,397	$ 682
Cash and cash equivalents at end of year	$ 10,626	$ 7,229

Cash and cash equivalents were $10,626 million at the end of 2003, an increase of $3,397 million, including $504 million of foreign exchange rate effects from the generally weaker U.S. dollar. Cash and cash equivalents increased $682 million in 2002, including $525 million due to foreign

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exchange, to end the year at $7,229 million. Cash flows from operating, investing and financing activities are discussed below. For additional details, see the Consolidated Statement of Cash Flows on page 46.

Although the corporation issues long-term debt from time to time and maintains a revolving commercial paper program, internally generated funds cover the majority of its financial requirements. The management of cash that may be temporarily available as surplus to the corporation's immediate needs is carefully controlled, both to optimize returns on cash balances, and to ensure that it is secure and readily available to meet the corporation's cash requirements as they arise.

Production from existing oil and gas fields has declined about 6 percent on average over the past two years and is expected to continue to decline in the future at approximately the same rate. The impact on cash flows from production is highly dependent on crude oil and natural gas prices. Decline rates vary widely by individual field and the overall decline rate for a geographical area will be heavily influenced by the type of reservoir and age of the fields in that region.

The corporation will need to continually find and develop new fields, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production and resulting cash flows in future periods. The corporation has been successful in offsetting the effects of field decline through these measures and anticipates similar results in the future. Projects are in place, or underway, to increase production capacity. However, these volume increases are subject to a variety or risks including project execution, operational outages, reservoir performance and regulatory changes.

The corporation's financial strength, as evidenced by its AAA/Aaa debt rating, enables it to make large, long term capital expenditures. ExxonMobil anticipates spending approximately $80 billion over the next eight years on upstream capital and exploration expenditures. The corporation has a large and diverse portfolio of development projects and exploration opportunities which helps mitigate the overall political and technical risks of the company's upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments. The purchase and sale of oil and gas properties have not had a significant impact on the amount or timing of operating cash flows.

Cash Flow from Operating Activities

2003

Cash provided by operating activities totaled $28.5 billion in 2003, a $7.2 billion increase from 2002 influenced by higher net income. Major sources of funds were net income of $21.5 billion and non-cash provisions of $9.0 billion for depreciation and depletion.

In 2003, ExxonMobil completed a divestment of interests in shares of Ruhrgas AG, a German gas transmission company. These shares were held in part by BEB Erdgas und Erdoel GmbH (BEB), an investment accounted for by the equity method, and in part by a consolidated affiliate in Germany. In 2002, cash in the amount of $1,466 million was received from BEB, an equity company, and included in cash flows from operating activities (see Ruhrgas transaction line on Statement of Cash Flows, page 46). This cash from BEB was a loan and was part of a restructuring that enabled BEB to transfer its holdings in Ruhrgas AG provided regulatory approval was received. No income was recorded in 2002.

In 2003, upon receipt of regulatory approvals, the Ruhrgas AG shares held by BEB were transferred, cash was received for the shares held by the consolidated affiliate and a one-time gain of $1,700 million after tax was recognized in net income. The $2,240 million reduction in 2003 cash flow from operating activities reflects the pre-tax gains from the transaction. The cash generated from these gains for the BEB portion of the transaction was reported in 2002. For the shares held by the consolidated affiliate, the cash received was reported in cash flows from investing activities in 2003.

2002

Cash provided by operating activities totaled $21.3 billion, down $1.6 billion from 2001. Major sources of funds were net income of $11.5 billion and non-cash provisions of $8.3 billion for depreciation and depletion. Cash from operating activities included $1,466 million of funds received from BEB, a German exploration and production company. The funds were loaned in connection with a restructuring that would enable BEB to transfer its holdings in Ruhrgas AG. Net income was recognized in 2003 upon finalization of regulatory reviews and completion of the transfer of the Ruhrgas AG shares.

Cash Flow from Investing Activities

2003

Cash used in investing activities totaled $10.8 billion in 2003, $1.0 billion higher than 2002. Spending for property, plant and equipment increased $1.4 billion, continuing to reflect the company’s active investment program. Proceeds from the sales of subsidiaries, investments and property, plant and equipment in 2003 were $2.3 billion, including $1.2 billion from the sale of an interest in Ruhrgas AG partly held by a consolidated affiliate.

2002

Cash used in investing activities totaled $9.8 billion, $1.6 billion higher than 2001 and included increased spending for property, plant and equipment and other investments and advances. Proceeds from the sales of subsidiaries, investments and property, plant and equipment were $2.8 billion, including the divestment of Colombian coal operations and the company’s copper business in Chile in 2002.

Cash Flow from Financing Activities

2003

Cash used in financing activities was $14.8 billion, an increase of $3.4 billion from 2002, reflecting higher levels of debt reductions and purchases of ExxonMobil shares. Dividend payments on common shares increased to $0.98 per share from $0.92 per share and totaled $6.5 billion, a payout of 30 percent. Total consolidated short-term and long-term debt declined $1.2 billion to $9.5 billion at year-end 2003. Shareholders’ equity increased $15.3 billion in 2003, to $89.9 billion, reflecting $21.5 billion of net income partly offset by $6.5 billion of dividends paid to ExxonMobil shareholders and $5.4 billion of net purchases of shares of ExxonMobil stock. Shareholders’ equity, and net assets and liabilities, also increased $4.4 billion, representing the foreign exchange translation effects of stronger foreign currencies on ExxonMobil’s operations outside the U.S.

During 2003, Exxon Mobil Corporation purchased 163 million shares of its common stock for the treasury at a gross cost of $5.9 billion. These purchases were to offset shares issued in conjunction with

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company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,700 million at the end of 2002 to 6,568 million at the end of 2003. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2002

Cash used in financing activities was $11.4 billion, down $3.7 billion, reflecting lower debt reductions. Dividend payments on common shares increased to $0.92 per share from $0.91 per share and totaled $6.2 billion, a payout of 54 percent. Total consolidated short-term and long-term debt was comparable at $10.7 billion. Shareholders' equity increased by $1.4 billion to $74.6 billion.

During 2002, Exxon Mobil Corporation purchased 127 million shares of its common stock for the treasury at a gross cost of $4.8 billion. These purchases were to offset shares issued in conjunction with company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,809 million at the end of 2001 to 6,700 million at the end of 2002. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the corporation's commitments outstanding at December 31, 2003. It provides data for easy reference from the consolidated balance sheet and from individual notes to the consolidated financial statements.

		Payments Due by Period				
Commitments	**Note Reference Number**	**2004**	**2005-2008**	**2009 and Beyond**	**2003 Total Amount**	**2002 Total Amount**
			(millions of dollars)			
Long-term debt [1]	15	$ —	$ 877	$3,879	$ 4,756	$ 6,655
– Due in one year [2]		1,903	—	—	1,903	884
Asset retirement obligations [3]	10	125	461	2,854	3,440	3,454
Pension obligations [4]	18	1,180	1,720	4,937	7,837	9,385
Operating leases [5]	11	1,299	2,730	2,160	6,189	6,945
Unconditional purchase obligations [6]	17	520	1,703	2,563	4,786	3,649
Take-or-pay obligations [7]		833	1,874	1,340	4,047	3,475
Firm capital commitments [8]		4,251	2,173	595	7,019	8,449

This table excludes commodity purchase obligations for which an active, highly-liquid market exists and which are expected to be re-sold shortly after purchase. Inclusion of such amounts would not be meaningful in assessing liquidity and cash flow, since such purchases will be offset in the same periods by cash received from sales.

Notes:

(1) Includes capitalized lease obligations of $370 million. Long-term debt amounts exclude the corporation's share of equity company debt, which is included in the calculation of return on average capital employed as shown on page 27.

(2) The amount due in one year is included in notes and loans payable of $4,789 million (note 7).

(3) The discounted present value of upstream asset retirement obligations, primarily asset removal costs at the completion of field life.

(4) The amount by which accumulated benefit obligations (ABO) exceeded the fair value of fund assets for certain U.S. and non-U.S. plans at year end (note 18 on page 65). For funded pension plans, this difference was $3.0 billion at December 31, 2003 (U.S. $0.5 billion, non-U.S. $2.5 billion). For unfunded plans, this was the ABO amount of $4.9 billion (U.S. $1.0 billion, non-U.S. $3.9 billion). The payments by period include expected contributions to funded pension plans in 2004 and estimated benefit payments for unfunded plans in all years.

(5) Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties.

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $4,786 million mainly pertain to pipeline throughput agreements and include $1,887 million of obligations to equity companies. The

present value of the total commitments, excluding imputed interest of $1,543 million, was $3,243 million.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than unconditional purchase obligations. The undiscounted obligations of $4,047 million mainly pertain to transportation, refining and natural gas purchases and include $622 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $663 million, totaled $3,384 million.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $7.0 billion at the end of 2003, compared with $8.4 billion at the end of 2002. These commitments were predominantly associated with upstream projects outside the U.S., of which the largest single commitment outstanding at the end of 2003 was $1.6 billion associated with the development of crude oil and natural gas resources in Malaysia. The corporation expects to fund the majority of these commitments through internal cash flow.

Guarantees

	Equity Company Obligations	Other Third Party Obligations	Total
		(millions of dollars)	
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 983	$ 983
Other guarantees	1,872	424	2,296
Total	$ 1,872	$ 1,407	$3,279

The corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2003 for $3,279 million, primarily relating to guarantees for notes, loans and performance under contracts (note 17). This included $983 million representing guarantees of non-U.S. excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements. Also included in this amount were guarantees by consolidated affiliates of $1,872 million, representing ExxonMobil’s share of obligations of

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certain equity companies. The above-mentioned guarantees are not reasonably likely to have a material current or future effect on the corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Financial Strength

On December 31, 2003, unused credit lines for short-term financing totaled approximately $4.3 billion (note 7 on page 50).

The table below shows the corporation's fixed charge coverage and consolidated debt to capital ratios. The data demonstrate the corporation's creditworthiness. Throughout this period, the corporation's long-term debt securities maintained the top credit rating from both Standard and Poor's (AAA) and Moody's (Aaa), a rating it has sustained for 85 years.

	2003	2002	2001
Fixed charge coverage ratio (times)	30.8	13.8	17.7
Debt to capital (percent)	9.3	12.2	12.4
Net debt to capital (percent) (1)	(1.2)	4.4	5.3
Credit rating	AAA/Aaa	AAA/Aaa	AAA/Aaa

(1) Debt net of all cash

Management views the corporation's financial strength, as evidenced by the above financial ratios and other similar measures, to be a competitive advantage of strategic importance. The corporation's sound financial position gives it the opportunity to access the world's capital markets in the full range of market conditions, and enables the corporation to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

In addition to the above commitments, the corporation makes limited use of derivative instruments, which are discussed in Risk Management on page 37 and note 14 on page 55.

Litigation and Other Contingencies

As discussed in note 17 to the consolidated financial statements, a number of lawsuits, including class actions, were brought in various courts against Exxon Mobil Corporation and certain of its subsidiaries relating to the accidental release of crude oil from the tanker Exxon Valdez in 1989. The vast majority of the compensatory claims have been resolved. All of the punitive damage claims were consolidated in the civil trial that began in May 1994.

In that trial, on September 24, 1996, the United States District Court for the District of Alaska entered a judgment in the amount of $5 billion in punitive damages to a class composed of all persons and entities who asserted claims for punitive damages from the corporation as a result of the Exxon Valdez grounding. ExxonMobil appealed the judgment. On November 7, 2001, the United States Court of Appeals for the Ninth Circuit vacated the punitive damage award as being excessive under the Constitution and remanded the case to the District Court for it to determine the amount of the punitive damage award consistent with the Ninth Circuit's holding. The Ninth Circuit upheld the compensatory damage award which has been paid. On December 6, 2002, the District Court reduced the punitive damage award from $5 billion to $4 billion. Both the plaintiffs and ExxonMobil appealed that decision to the Ninth Circuit. The Ninth Circuit panel vacated the District Court's $4 billion punitive damage award without argument and sent the case back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm*. On January 28, 2004, the District Court reinstated the punitive damage award at $4.5 billion plus interest. ExxonMobil will appeal the decision to the Ninth Circuit. Management believes that the likelihood of the jury verdict being upheld is remote. While it is reasonably possible that a liability may have been incurred arising from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

On December 19, 2000, a jury in Montgomery County, Alabama, returned a verdict against the corporation in a dispute over royalties in the amount of $87.69 million in compensatory damages and $3.42 billion in punitive damages in the case of *Exxon Corporation v. State of Alabama, et al*. The verdict was upheld by the trial court on May 4, 2001. On December 20, 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and on November 14, 2003, a state district court jury in Montgomery, Alabama returned a verdict against Exxon Mobil Corporation. The verdict included $63.5 million in compensatory damages and $11.8 billion in punitive damages. ExxonMobil believes the verdict is not justified by the evidence and that the amount of the award is grossly excessive and unconstitutional. ExxonMobil will appeal the decision. Management believes that the likelihood of the jury verdict being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over royalties, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

On May 22, 2001, a state court jury in New Orleans, Louisiana, returned a verdict against the corporation and three other entities in a case brought by a landowner claiming damage to his property. The property had been leased by the landowner to a company that performed pipe cleaning and storage services for customers, including the corporation. The jury awarded the plaintiff $56 million in compensatory damages (90 percent to be paid by the corporation) and $1 billion in punitive damages (all to be paid by the corporation). The damage related to the presence of naturally occurring radioactive material (NORM) on the site resulting from pipe cleaning operations. The award has been upheld at the trial court. ExxonMobil has appealed the judgment to the Louisiana Fourth Circuit Court of Appeals and believes that the judgment should be set aside or substantially reduced on factual and constitutional grounds. Management believes that the likelihood of the jury verdict being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over property damages, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

Issues pending before the U.S. Tax Court for 1979 have been resolved. While issues for 1980-93 remain pending before the court, the ultimate resolution of these issues is not expected to have a materially adverse effect upon the corporation’s operations or financial condition.

Based on a consideration of all relevant facts and circumstances, the corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a materially adverse effect upon the corporation’s operations or financial condition. There are no events or uncertainties known to management beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

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CAPITAL AND EXPLORATION EXPENDITURES

	2003		2002	
	U.S.	Non-U.S.	U.S.	Non-U.S.
	(millions of dollars)			
Upstream [1]	$2,125	$ 9,863	$2,357	$ 8,037
Downstream	1,244	1,537	980	1,470
Chemicals	333	359	575	379
Other	64	—	45	112
Total	$3,766	$11,759	$3,957	$ 9,998

(1) Exploration expenses included

Capital and exploration expenditures in 2003 were $15.5 billion, up from $14.0 billion in 2002, reflecting the corporation's active investment program and impacts of the weaker U.S. dollar. Capital and exploration expenditures in the U.S. totaled $3.8 billion in 2003, down $0.2 billion from 2002, reflecting lower spending in the upstream and chemicals, partly offset by increased spending in the downstream. Spending outside the U.S. of $11.8 billion was up $1.8 billion from 2002, reflecting higher expenditures in the upstream, partly offset by lower expenditures in chemicals.

Upstream spending was up 15 percent to $12.0 billion in 2003, from $10.4 billion in 2002, as a result of higher spending on major projects in Africa, the Caspian, Qatar and Russia. These increases were partly offset by lower development drilling in the U.S. and United Kingdom. Capital investments in the downstream totaled $2.8 billion in 2003, up $0.3 billion from 2002, primarily reflecting investments in cogeneration plants in North America and increased spending required for low-sulfur motor fuels. Chemicals capital expenditures were $0.7 billion in 2003, down $0.3 billion from 2002, due to lower spending on base activities and the absence of the acquisition of the joint venture partner's interest in Advanced Elastomers Systems in 2002.

TAXES

	2003	2002	2001
		(millions of dollars)	
Income taxes	$11,006	$ 6,499	$ 8,967
Excise taxes	23,855	22,040	21,907
All other taxes and duties	40,107	35,746	35,653
Total	$74,968	$64,285	$66,527
Total effective tax rate	36.4%	39.8%	39.3%

2003

Income, excise and all other taxes totaled $75.0 billion in 2003, an increase of $10.7 billion or 17 percent from 2002. Income tax expense, both current and deferred, was $11.0 billion, $4.5 billion higher than 2002, reflecting higher pre-tax income in 2003. The effective tax rate was 36.4 percent in 2003. Excluding the income tax effects of the 2003 gain on the Ruhrgas AG share transfer and settlement of a U.S. tax dispute, the effective rate in 2003 was similar to the prior year. During both periods, the corporation continued to benefit from the favorable resolution of other tax-related issues. Excise and all other taxes and duties of $64.0 billion in 2003 increased $6.2 billion from 2002, reflecting higher prices and foreign exchange effects.

2002

Income, excise and all other taxes and duties totaled $64.3 billion in 2002, a decrease of $2.2 billion or 3 percent from 2001. Income tax expense, both current and deferred, was $6.5 billion compared to $9.0 billion in 2001, reflecting lower pre-tax income in 2002. The effective tax rate of 39.8 percent in 2002 compared to 39.3 percent in 2001. During 2002, the company continued to benefit from favorable resolution of tax-related issues. Excise and all other taxes and duties were $57.8 billion.

MERGER EXPENSES AND REORGANIZATION RESERVES

In association with the merger between Exxon and Mobil, $410 million pre-tax ($275 million after-tax) and $748 million pre-tax ($525 million after-tax) of costs were recorded as merger related expenses in 2002 and 2001, respectively. Charges included separation expenses related to workforce reductions (approximately 8,200 employees at year-end 2002), plus implementation and merger closing costs. The separation reserve balance at year-end 2003 of approximately $48 million is expected to be expended mainly in 2004. Merger related expenses for the period 1999 to 2002 cumulatively totaled approximately $3.2 billion pre-tax. Pre-tax operating synergies associated with the merger, including cost savings, efficiency gains and revenue enhancements, cumulatively reached over $7 billion by 2002. Reflecting the completion of merger related activities, merger expenses were not reported in 2003.

The following table summarizes the activity in the reorganization reserves. The 2001 opening balance represents accruals for provisions taken in prior years.

	Opening Balance	Additions	Deductions	Balance at Year End
		(millions of dollars)		
2001	$ 339	$ 187	$ 329	$ 197
2002	197	93	189	101
2003	101	—	53	48

ASSET RETIREMENT OBLIGATIONS AND ENVIRONMENTAL COSTS

Asset Retirement Obligations

The methodology of accounting for asset retirement obligations was modified as of January 1, 2003 per FAS 143 (see page 32, Accounting Change). The fair values of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically at the time assets are installed, with an offsetting amount booked as additions to property, plant and equipment ($253 million for 2003). Over time, the liabilities are accreted for the increase in their present value, with this effect included in expenses ($174 million in 2003). Payments made for asset retirement obligations in 2003 were $113 million and the ending balance of the obligations recorded on the balance sheet at December 31, 2003 totaled $3,440 million.

Environmental Costs

	2003	2002
	(millions of dollars)	
Capital expenditures	$1,306	$1,054
Included in expenses	1,497	1,289
Total	$2,803	$2,343

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Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on the air, water and ground. This includes a significant investment in refining technology to manufacture low-sulfur motor fuels and projects to reduce nitrogen oxide and sulfur oxide emissions. ExxonMobil's 2003 worldwide environmental costs for all such preventative and remediation steps were about $2.8 billion, of which $1.3 billion were capital expenditures and $1.5 billion were included in expenses. The total cost for such activities is expected to decrease to about $2.6 billion in both 2004 and 2005 (with capital expenditures representing just over 40 percent of the total). The projected decrease reflects the near completion of low-sulfur motor fuels projects in Canada and the U.S., partly offset by increases in Europe and Japan.

The corporation accrues liabilities for environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multi-party sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multi-party sites mitigates ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations, financial condition or liquidity. Provisions made in 2003 for new environmental liabilities were $275 million (included in the $1.5 billion of 2003 expenses noted above) and the balance sheet reflects accumulated liabilities of $528 million as of December 31, 2003 and $468 million as of December 31, 2002.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations	2003	2002	2001
Crude oil and NGL ($/barrel)	$26.64	$22.25	$21.10
Natural gas ($/kcf)	4.02	2.77	3.39

Crude oil, natural gas, petroleum product and chemical prices have fluctuated widely in response to changing market forces. The impacts of these price fluctuations on earnings from upstream operations, downstream operations and chemicals operations have been varied, tending at times to be offsetting. Nonetheless, the global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the corporation's businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of our projects, underscore the importance of maintaining a strong financial position. Management views the corporation's financial strength, including the AAA and Aaa ratings of its long-term debt securities by Standard and Poor's and Moody's, as a competitive advantage.

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegment sales are market related. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About half of the corporation's intersegment sales are crude oil produced by the upstream and sold to the downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

Although price levels of crude oil and natural gas may rise or fall significantly over the short- to medium term due to political events, OPEC actions and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the corporation tests the viability of all of its assets based on long-term price projections. The corporation's assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management programs. Investment opportunities are tested against a variety of market conditions, including low price scenarios. As a result, investments that would succeed only in highly favorable price environments are screened out of the investment plan.

The corporation has had an active asset management program in which under-performing assets are either improved to acceptable levels or considered for divestment. The asset management program involves a disciplined, regular review to ensure that all assets are contributing to the corporation's strategic and financial objectives. The result has been the creation of a very efficient capital base and has meant that the corporation has seldom been required to write-down the carrying value of assets, even during periods of low commodity prices.

Risk Management

The corporation's size, geographic diversity and the complementary nature of the upstream, downstream and chemicals businesses mitigate the corporation's risk from changes in interest rates, currency rates and commodity prices. The corporation relies on these operating attributes and strengths to reduce enterprise-wide risk. As a result, the corporation makes limited use of derivatives to offset exposures arising from existing transactions.

The corporation does not trade in derivatives nor does it use derivatives with leverage features. The corporation maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity. The corporation's derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity. Interest rate, foreign exchange rate and commodity price exposures arising from derivative contracts undertaken in accordance with the corporation's policies have not been significant.

Derivatives	**2003**	**2002**	**2001**
		(millions of dollars)	
Net receivable/(payable)	$(17)	$ 20	$(50)
Net gain/(loss), before-tax	4	(35)	23

The fair value of derivatives outstanding and recorded on the balance sheet are shown in the table above. This is the amount that the corporation would have paid to or received from third parties if these derivatives had been settled. These derivative fair values were substantially offset by the fair values of the underlying exposures being hedged. The gains/losses before-tax include the offsetting amounts from the changes in fair value of the items being hedged by the derivatives. The fair value of derivatives outstanding at year-end 2003 and gain recognized during the year are immaterial in relation to the corporation's year-end cash balance of $10.6 billion, total assets of $174.3 billion or net income for the year of $21.5 billion.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Debt-Related Instruments

The corporation is exposed to changes in interest rates, primarily as a result of its short-term debt and long-term debt carrying floating interest rates. The corporation makes limited use of interest rate swap agreements to adjust the ratio of fixed and floating rates in the debt portfolio. The impact of a 100 basis point change in interest rates affecting the corporation's debt would not be material to earnings, cash flow or fair value.

Foreign Currency Exchange Rate Instruments

The corporation conducts business in many foreign currencies and is subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in foreign currency exchange rates on ExxonMobil's geographically diverse operations are varied and often offsetting in amount. The corporation makes limited use of currency exchange contracts to reduce the risk of adverse foreign currency movements related to certain foreign currency debt obligations. Exposure from market rate fluctuations related to these contracts is not material. Aggregate foreign exchange transaction gains and losses included in net income are discussed in note 5 on page 50.

Commodity Instruments

The corporation makes limited use of commodity forwards, swaps and futures contracts of short duration to mitigate the risk of unfavorable price movements on certain crude, natural gas and petroleum product purchases and sales. Commodity price exposure related to these contracts is not material.

Inflation and Other Uncertainties

The general rate of inflation in most major countries of operation has been relatively low in recent years, and the associated impact on costs has been countered by cost reductions from efficiency and productivity improvements.

The operations and earnings of the corporation and its affiliates throughout the world have been, and may in the future be, affected from time to time in varying degree by political developments and laws and regulations, such as forced divestiture of assets; restrictions on production, imports and exports; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights and environmental regulations. Both the likelihood of such occurrences and their overall effect upon the corporation vary greatly from country to country and are not predictable.

RECENTLY ISSUED STATEMENTS OF FINANCIAL ACCOUNTING STANDARDS

In December 2003, the Financial Accounting Standards Board issued a revised Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities," replacing the original interpretation issued in January 2003. FIN 46 provides guidance on when certain entities should be consolidated or the interests in those entities should be disclosed by enterprises that do not control them through majority voting interest. Under FIN 46, entities are required to be consolidated by enterprises that lack majority voting interest when equity investors of those entities have insignificant capital at risk or they lack voting rights, the obligation to absorb expected losses, or the right to receive expected returns. Entities identified with these characteristics are called variable interest entities and the interests that enterprises have in these entities are called variable interests. These interests can derive from certain guarantees, leases, loans or other arrangements that result in risks and rewards that are disproportionate to the voting interests in the entities.

The provisions of FIN 46 must be immediately applied for variable interest entities created after January 31, 2003 and for variable interests in entities commonly referred to as "special purpose entities." For all other variable interest entities, implementation is required by March 31, 2004.

There have been no variable interest entities created after January 31, 2003 in which the corporation has an interest. The corporation identified three venture operating entities in which the corporation has variable interests primarily through lease commitments and certain guarantees extended by the corporation. The corporation chose to implement FIN 46 in the fourth quarter 2003 by consolidating these entities, which were previously accounted for under the equity method. There was no effect on net income, because the corporation was already recording its share of net income of these entities. The impact to the balance sheet was to increase both assets and liabilities by about $500 million. However, there was no change to the calculation of return on average capital employed, because the corporation already includes its share of equity company debt in the determination of average capital employed.

REPORTING INVESTMENTS IN MINERAL INTERESTS IN OIL AND GAS PROPERTIES

Statements of Financial Accounting Standards No. 141 (FAS 141), "Business Combinations," and No. 142 (FAS 142), "Goodwill and Other Intangible Assets," were issued by the Financial Accounting Standards Board (FASB) in June 2001 and became effective for the corporation on July 1, 2001 and January 1, 2002, respectively. Currently, the Emerging Issues Task Force (EITF) is considering the issue of whether FAS 141 and 142 require interests held under oil, gas and mineral leases to be separately classified as intangible assets on the balance sheets of companies in the extractive industries. If such interests were deemed to be intangible assets by the EITF, mineral rights to extract oil and gas for both undeveloped and developed leaseholds would be classified separately from oil and gas properties as intangible assets on the corporation's balance sheet. Historically the corporation has capitalized the cost of oil and gas leasehold interests in accordance with statement of Financial Accounting Standard No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies." Also, consistent with industry practice, the corporation has reported these assets as part of tangible oil and gas property, plant and equipment.

This interpretation of FAS 141 and 142 would only affect the classification of oil and gas leaseholds on the corporation's balance sheet, and would not affect total assets, net worth or cash flows. The corporation's results of operations would not be affected, since these leasehold costs would continue to be amortized in accordance with FAS 19. The amount that is subject to reclassification as of December 31, 2003 was $4.5 billion, and as of December 31, 2002 was $4.6 billion.

CRITICAL ACCOUNTING POLICIES

The corporation's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to

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make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The following summary provides further information about the critical accounting policies and the judgments that are made by the corporation in the application of those policies.

Oil and Gas Reserves

Evaluations of oil and gas reserves are important to the effective management of upstream assets. They are integral to making investment decisions about oil and gas properties such as whether development should proceed or enhanced recovery methods should be undertaken. Oil and gas reserve quantities are also used as the basis of calculating the unit-of-production rates for depreciation and evaluating for impairment. Oil and gas reserves are divided between proved and unproved reserves. Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that 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. Unproved reserves are those with less than reasonable certainty of recoverability and are classified as either probable or possible. Probable reserves are reserves that are more likely to be recovered than not and possible reserves are less likely to be recovered than not.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations and extrapolations of well information such as flow rates and reservoir pressure declines. In certain deepwater fields, proved reserves are recorded in a limited number of cases before flow tests are conducted because of the safety and cost implications of conducting the tests. In those situations, other industry accepted analyses are used such as information from well logs, a thorough pressure and fluid sampling program, conventional core data obtained across the entire reservoir interval and nearby analog data. Historically, proved reserves recorded using these methods have been immaterial when compared to the corporation's total proved reserves and have also been validated by subsequent flow tests or actual production levels. Furthermore, the corporation only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. Although the corporation is reasonably certain that proved reserves will be produced, the timing and ultimate recovery can be effected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in projects of long term oil and gas price levels.

At year-end 2003, proved oil and gas reserves were 21.2 billion oil-equivalent barrels. These proved reserves can be further subdivided into developed and undeveloped reserves. The percentage of proved developed reserves has remained relatively stable over the past five years at over 60 percent of total proved reserves, indicating that proved reserves are consistently moved from undeveloped to developed status. Management is not aware of any factors that would significantly change this historical relationship in the next several years. The corporation added 1.7 billion oil-equivalent barrels to proved reserves in 2003. The majority of these additions were undeveloped reserves. Over time these reserves will be reclassified to the developed category as wells are drilled, existing wells are recompleted and/or facilities to collect and deliver the production from existing and future wells are installed. Major development projects typically take two-to-four years from the time of recording reserves to start of production from these reserves. The corporation's 2003 proved reserves additions replaced 108 percent of the 1.6 billion oil-equivalent barrels produced, excluding sales. With sales included, the corporation replaced 106 percent of reserves produced. Both reserve replacement percentages exclude tar sands. This is the tenth consecutive year that the corporation's reserve replacement has exceeded 100 percent.

Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to the evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with the performance of improved recovery projects, fiscal terms, and significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

The corporation uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. The corporation continues to carry as an asset the cost of drilling exploratory wells that find sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure is made and drilling of additional exploratory wells is under way or firmly planned for the near future. Once exploration activities demonstrate that sufficient quantities of commercially producible reserves have been discovered, continued capitalization is dependent on project reviews, which take place at least annually, to ensure that satisfactory progress toward ultimate development of the reserves is being achieved. Exploratory well costs not meeting these criteria are charged to expense. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field. The corporation uses this accounting policy instead of the "full cost" method because it provides a more timely accounting of the success or failure of the corporation's exploration and production activities. If the full cost method were used, all costs would be capitalized and depreciated on a country-by-country basis. The capitalized costs would be subject to an impairment test by country. The full cost method would tend to delay the expense recognition of unsuccessful projects.

Impact of Oil and Gas Reserves on Depreciation. The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. It is the ratio of (1) actual volumes produced to (2) total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods) applied to the (3) asset cost. The volumes produced and asset cost are known and while proved developed reserves have a high probability of recoverability they are based on estimates that are subject to some variability. This variability has generally resulted in net upward revisions of proved reserves in existing fields, as more information becomes available through research and production. Revisions have averaged 650 million oil-equivalent barrels per year over the last five years, and have resulted from effective reservoir management and the application of new technology. While the upward revisions the corporation has made in the past are an indicator of variability, they have had a very small impact on the unit-of-production rates because they have been small compared to the large reserves base.

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Impact of Oil and Gas Reserves and Prices on Testing for Impairment. Proved oil and gas properties held and used by the corporation are reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In general, analyses are based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value.

The corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses monitor the performance of assets against corporate objectives. They also assist the corporation in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. The impairment evaluation triggers include a significant decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected, and historical and current negative operating losses.

In general, the corporation does not view temporarily low oil prices as a triggering event for conducting the impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop precipitously, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry prices over the long term and these cannot be accurately predicted. Accordingly, any impairment tests that the corporation performs make use of the corporation's long-term price assumptions for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used in the corporation's annual planning and budgeting processes and are also used for capital investment decisions. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Annual volumes are based on individual field production profiles which are also updated annually. Prices for natural gas and other products sold under contract are based on corporate plan assumptions developed annually by major region/contract and used for investment evaluation purposes. Cash flow estimates for impairment testing exclude the use of derivative instruments.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves can be found on pages 70 to 74. The standardized measure of discounted future cash flows on page 74 is based on the year-end 2003 price applied for all future years, as required under Statement of Financial Accounting Standards No. 69 (FAS 69). Future prices used for any impairment tests will vary from the one used in the FAS 69 disclosure, and could be lower or higher for any given year.

Consolidations

The consolidated financial statements include the accounts of those significant subsidiaries that the corporation controls. They also include the corporation's undivided interests in upstream assets and liabilities. Amounts representing the corporation's percentage interest in the underlying net assets of other significant affiliates that it does not control, but exercises significant influence, are included in "Investments and advances"; the corporation's share of the net income of these companies is included in the consolidated statement of income caption "Income from equity affiliates." The accounting for these non-consolidated companies is referred to as the equity method of accounting.

Majority ownership is normally the indicator of control that is the basis on which subsidiaries are consolidated. However, certain factors may indicate that a majority-owned investment is not controlled and therefore should be accounted for using the equity method of accounting. These factors occur where the minority shareholders are granted by law or by contract substantive participating rights. These include the right to approve operating policies, expense budgets, financing and investment plans and management compensation and succession plans.

The corporation consolidates certain affiliates in which it has less than a majority ownership, because of guarantees or other arrangements that create majority economic interests in those affiliates which are greater than the corporation's voting interests.

Additional disclosures of summary balance sheet and income information for those subsidiaries accounted for under the equity method of accounting can be found in note 8 on page 51. The corporation believes this to be important information necessary to a full understanding of the corporation's financial statements.

Investments in companies that are partially owned by the corporation are integral to the corporation's operations. In some cases they serve to balance worldwide risks and in others they provide the only available means of entry into a particular market or area of interest. The other parties who also have an equity interest in these companies are either independent third parties or host governments that share in the business results according to their percentage ownership. The corporation does not invest in these companies in order to remove liabilities from its balance sheet. In fact, the corporation has long been on record supporting an alternative accounting method that would require each investor to consolidate its percentage share of all assets and liabilities in these partially owned companies rather than only the percentage in the net equity. This method of accounting for investments in partially owned companies is not permitted by GAAP except where the investments are in the direct ownership of a share in the upstream assets and liabilities. However, for purposes of calculating return on average capital employed, which is not covered by GAAP standards, the corporation includes its share of debt of these partially owned companies in the determination of average capital employed.

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Annuity Benefits

The corporation and its affiliates sponsor over 100 defined benefit (pension) plans in more than 50 countries. The funding arrangement for each plan depends on the prevailing practices and regulations of the countries where the company operates. Note 18, pages 63 to 65, provides details on pension obligations, fund assets and pension expense.

Some of these plans (primarily non-U.S.) provide pension benefits which are paid directly by their sponsoring affiliates out of corporate cash flow rather than a separate pension fund. Book reserves are established for these plans, because tax conventions and regulatory practices do not encourage advance funding. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

For funded plans, including many in the U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in compliance with the requirements of governmental authorities, and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, these standards often require approaches and assumptions which differ from those used for accounting purposes. Contributions to funded plans totaled $2,833 million in 2003 (U.S. $2,054 million, non-U.S. $779 million).

The corporation will continue to make contributions to these funded plans as necessary. All defined benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the corporation or the respective sponsoring affiliate.

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations, and the long-term rate for future salary increases. All the pension assumptions are reviewed annually by outside actuaries and senior financial management. These assumptions are adjusted only as appropriate to reflect changes in market rates and outlook. For example, the long-term expected earnings rate on U.S. pension plan assets was reduced in 2003 from 9.5 percent to 9.0 percent. This compares to an actual rate of return over the past decade of 11 percent. The company establishes the long-term expected rate of return by developing a forward-looking long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the pension fund earnings rate would increase pension expense by approximately $80 million before-tax.

Under GAAP, differences between actual returns on fund assets versus the long-term expected return are not recorded in the year that the difference occurs, but rather are amortized in pension expense, along with other actuarial gains and losses, over the expected remaining service life of employees. The corporation uses the fair value of the plan assets at year end to determine the amount of the actuarial gain or loss that will be amortized and does not use a moving average value of plan assets.

Due to the general decline in the market value of pension assets and in interest rates in 2002, and the weaker U.S. dollar in 2003, pension expense grew from $995 million in 2002 (U.S. $470 million, non-U.S. $525 million) to $1,938 million in 2003 (U.S. $1,015 million, non-U.S. $923 million).

Litigation and Other Contingencies

A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits and tax disputes. These are summarized on page 35, with a more extensive discussion included in note 17 on page 62.

GAAP requires that liabilities for contingencies be recorded when it is probable that a liability has been incurred before the date of the balance sheet and that the amount can be reasonably estimated. These amounts are not reduced by amounts that may be recovered under insurance or claims against third parties, but undiscounted receivables from insurers or other third parties may be accrued separately. The corporation revises such accruals in light of new information.

Significant management judgment is required related to contingent liabilities and the outcome of litigation because both are difficult to predict. However, the corporation has been successful in defending litigation in the past, and actual payments have not been material. In the corporation’s experience, large claims often do not result in large awards. Large awards are often reversed or substantially reduced as a result of appeal or settlement.

Foreign Currency Translation

The method of translating the foreign currency financial statements of the corporation’s international subsidiaries into U.S. dollars is prescribed by GAAP. Under these principles, it is necessary to select the functional currency of these subsidiaries. The functional currency is the currency of the primary economic environment in which the subsidiary operates. Management selects the functional currency after evaluating this economic environment. Downstream and chemicals operations normally use the local currency, except in highly inflationary countries, primarily Latin America, as well as in Singapore, which uses the U.S. dollar, because it predominantly sells into the U.S. dollar export market. Upstream operations also use the local currency as the functional currency, except where crude and natural gas production is predominantly sold in the export market in U.S. dollars. These operations, which use the U.S. dollar as their functional currency, are in Malaysia, Indonesia, Angola, Nigeria, Equatorial Guinea and the Middle East countries.

Factors considered by management when determining the functional currency for a subsidiary include: the currency used for cash flows related to individual assets and liabilities; the responsiveness of sales prices to changes in exchange rates; whether sales are into local markets or exported; the currency used to acquire raw materials, labor, services and supplies; sources of financing; and significance of intercompany transactions.

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MANAGEMENT'S DISCUSSION OF INTERNAL CONTROLS FOR FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal controls and procedures for the preparation of financial reports. Accordingly, comprehensive procedures and practices are in place. These procedures and practices are designed to provide reasonable assurance that the corporation's transactions are properly authorized; the corporation's assets are safeguarded against unauthorized or improper use; and the corporation's transactions are properly recorded and reported to permit the preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles.

Internal controls and procedures for financial reporting are regularly reviewed by management and by the ExxonMobil internal audit function and findings are shared with the Audit Committee of the Board. In addition, PricewaterhouseCoopers, the corporation's independent auditor, who reports to the Audit Committee of the Board, considers and selectively tests internal controls in planning and performing its audits. Management's review of the design and operation of these controls and procedures in 2003, including review as of year end, did not identify any significant deficiencies or material weaknesses, including any deficiencies which could adversely affect the corporation's ability to record, process, summarize and report financial data.

/s/ Lee R. Raymond	/s/ Donald D. Humphreys	/s/ Frank A. Risch
Lee R. Raymond Chief Executive Officer	Donald D. Humphreys Vice President and Controller (Principal Accounting Officer)	Frank A. Risch Vice President and Treasurer (Principal Financial Officer)

REPORT OF INDEPENDENT AUDITORS

[LOGO OF PRICEWATERHOUSECOOPERS]

To the Shareholders of Exxon Mobil Corporation

In our opinion, the consolidated financial statements appearing on pages 43 through 68 present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiary companies at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the corporation's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the corporation changed its method of accounting for asset retirement obligations in 2003.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 25, 2004

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CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2003	2002	2001
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue [(1)]		$237,054	$200,949	$208,715
Income from equity affiliates	8	4,373	2,066	2,174
Other income		5,311	1,491	1,896
Total revenues and other income		$246,738	$204,506	$212,785
Costs and other deductions				
Crude oil and product purchases		$107,658	$ 90,950	$ 92,257
Production and manufacturing expenses		21,260	17,831	17,743
Selling, general and administrative expenses		13,396	12,356	12,898
Depreciation and depletion		9,047	8,310	7,848
Exploration expenses, including dry holes		1,010	920	1,175
Merger related expenses	4	—	410	748
Interest expense		207	398	293
Excise taxes [(1)]	20	23,855	22,040	21,907
Other taxes and duties	20	37,645	33,572	33,377
Income applicable to minority and preferred interests		694	209	569
Total costs and other deductions		$214,772	$186,996	$188,815
Income before income taxes		$ 31,966	$ 17,510	$ 23,970
Income taxes	20	11,006	6,499	8,967
Income from continuing operations		$ 20,960	$ 11,011	$ 15,003
Discontinued operations, net of income tax	3	—	449	102
Extraordinary gain, net of income tax	3	—	—	215
Cumulative effect of accounting change, net of income tax	2, 10	550	—	—
Net income		$ 21,510	$ 11,460	$ 15,320
Net income per common share *(dollars)*	13			
Income from continuing operations		$ 3.16	$ 1.62	$ 2.19
Discontinued operations, net of income tax		—	0.07	0.01
Extraordinary gain, net of income tax		—	—	0.03
Cumulative effect of accounting change, net of income tax		0.08	—	—
Net income		$ 3.24	$ 1.69	$ 2.23
Net income per common share – assuming dilution *(dollars)*	13			
Income from continuing operations		$ 3.15	$ 1.61	$ 2.17
Discontinued operations, net of income tax		—	0.07	0.01
Extraordinary gain, net of income tax		—	—	0.03
Cumulative effect of accounting change, net of income tax		0.08	—	—
Net income		$ 3.23	$ 1.68	$ 2.21

(1) *Sales and other operating revenue includes excise taxes of $23,855 million for 2003, $22,040 million for 2002 and $21,907 million*

for 2001.

The information on pages 47 through 68 is an integral part of these statements.

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CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2003	Dec. 31 2002
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		$ 10,626	$ 7,229
Notes and accounts receivable, less estimated doubtful amounts	7	24,309	21,163
Inventories			
Crude oil, products and merchandise	1	7,665	6,827
Materials and supplies		1,292	1,241
Prepaid taxes and expenses		2,068	1,831
Total current assets		$ 45,960	$ 38,291
Investments and advances	9	15,535	12,111
Property, plant and equipment, at cost, less accumulated depreciation and depletion	10	104,965	94,940
Other assets, including intangibles, net		7,818	7,302
Total assets		$174,278	$152,644
Liabilities			
Current liabilities			
Notes and loans payable	7	$ 4,789	$ 4,093
Accounts payable and accrued liabilities	7	28,445	25,186
Income taxes payable		5,152	3,896
Total current liabilities		$ 38,386	$ 33,175
Long-term debt	15	4,756	6,655
Annuity reserves	18	9,609	11,202
Accrued liabilities		5,283	5,252
Deferred income tax liabilities	20	20,118	16,484
Deferred credits and other long-term obligations		2,829	2,511
Equity of minority and preferred shareholders in affiliated companies		3,382	2,768
Total liabilities		$ 84,363	$ 78,047
Shareholders’ equity			
Benefit plan related balances		$ (634)	$ (450)
Common stock without par value (9,000 million shares authorized)		4,468	4,217
Earnings reinvested		115,956	100,961
Accumulated other nonowner changes in equity			
Cumulative foreign exchange translation adjustment		1,421	(3,015)
Minimum pension liability adjustment		(2,446)	(2,960)
Unrealized gains/(losses) on stock investments		511	(79)
Common stock held in treasury (1,451 million shares in 2003 and 1,319 million shares in 2002)		(29,361)	(24,077)
Total shareholders’ equity		$ 89,915	$ 74,597
Total liabilities and shareholders’ equity		$174,278	$152,644

The information on pages 47 through 68 is an integral part of these statements.

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CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

		2003		2002		2001	
	Note Reference Number	Shareholders' Equity	Nonowner Changes in Equity	Shareholders' Equity	Nonowner Changes in Equity	Shareholders' Equity	Nonowner Changes in Equity
				(millions of dollars)			
Benefit plan related balances							
At beginning of year		$ (450)		$ (159)		$ (235)	
Restricted stock award		(358)		(361)		—	
Amortization		107		11		—	
Other		67		59		76	
At end of year		$ (634)		$ (450)		$ (159)	
Common stock	13						
At beginning of year		4,217		3,789		3,661	
Issued		—		—		—	
Other		251		428		128	
At end of year		$ 4,468		$ 4,217		$ 3,789	
Earnings reinvested							
At beginning of year		100,961		95,718		86,652	
Net income for the year		21,510	$ 21,510	11,460	$ 11,460	15,320	$ 15,320
Dividends – common shares		(6,515)		(6,217)		(6,254)	
At end of year		$ 115,956		$ 100,961		$ 95,718	
Accumulated other nonowner changes in equity							
At beginning of year		(6,054)		(6,590)		(5,189)	
Foreign exchange translation adjustment		4,436	4,436	2,932	2,932	(1,085)	(1,085)
Minimum pension liability adjustment	18	514	514	(2,425)	(2,425)	(225)	(225)

Unrealized gains/(losses) on stock investments		590	590	29	29	(91)	(91)
At end of year		$ (514)		$ (6,054)		$ (6,590)	
Total			$ 27,050		$ 11,996		$ 13,919
Common stock held in treasury							
At beginning of year		(24,077)		(19,597)		(14,132)	
Acquisitions, at cost		(5,881)		(4,798)		(5,721)	
Dispositions		597		318		256	
At end of year		$ (29,361)		$ (24,077)		$ (19,597)	
Shareholders' equity at end of year		$ 89,915		$ 74,597		$ 73,161	

		Share Activity		
		2003	2002	2001
		(millions of shares)		
Common stock				
Issued	13			
At beginning of year		8,019	8,019	8,019
Issued		—	—	—
At end of year		8,019	8,019	8,019
Held in treasury	13			
At beginning of year		(1,319)	(1,210)	(1,089)
Acquisitions		(163)	(127)	(139)
Dispositions		31	18	18
At end of year		(1,451)	(1,319)	(1,210)
Common shares outstanding at end of year		6,568	6,700	6,809

The information on pages 47 through 68 is an integral part of these statements.

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CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2003	2002	2001
			(millions of dollars)	
Cash flows from operating activities				
Net income				
Accruing to ExxonMobil shareholders		$ 21,510	$ 11,460	$ 15,320
Accruing to minority and preferred interests		694	209	569
Cumulative effect of accounting change, net of income tax	2	(550)	—	—
Adjustments for non-cash transactions				
Depreciation and depletion		9,047	8,310	7,848
Deferred income tax charges/(credits)		1,827	297	650
Annuity provisions		(1,489)	(500)	349
Accrued liability provisions		264	(90)	149
Dividends received greater than/(less than) equity in current earnings of equity companies		(402)	(170)	78
Extraordinary gain, before income tax		—	—	(194)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) – Notes and accounts receivable		(1,286)	(305)	3,062
– Inventories		(100)	353	154
– Prepaid taxes and expenses		42	32	118
Increase/(reduction) – Accounts and other payables		1,130	365	(5,103)
Ruhrgas transaction	6	(2,240)	1,466	—
All other items – net		51	(159)	(111)
Net cash provided by operating activities		$ 28,498	$ 21,268	$ 22,889
Cash flows from investing activities				
Additions to property, plant and equipment		$(12,859)	$(11,437)	$ (9,989)
Sales of subsidiaries, investments and property, plant and equipment	6	2,290	2,793	1,078
Additional investments and advances		(809)	(2,012)	(1,035)
Collection of advances		536	898	1,735
Net cash used in investing activities		$(10,842)	$ (9,758)	$ (8,211)
Cash flows from financing activities				
Additions to long-term debt		$ 127	$ 396	$ 547
Reductions in long-term debt		(914)	(246)	(506)
Additions to short-term debt		715	751	705
Reductions in short-term debt		(1,730)	(927)	(1,212)
Additions/(reductions) in debt with less than 90 day maturity		(322)	(281)	(2,306)
Cash dividends to ExxonMobil shareholders		(6,515)	(6,217)	(6,254)
Cash dividends to minority interests		(430)	(169)	(194)
Changes in minority interests and sales/(purchases) of affiliate stock		(247)	(161)	(401)
Common stock acquired		(5,881)	(4,798)	(5,721)
Common stock sold		434	299	301
Net cash used in financing activities		$(14,763)	$(11,353)	$(15,041)
Effects of exchange rate changes on cash		$ 504	$ 525	$ (170)

Increase/(decrease) in cash and cash equivalents	$ 3,397	$ 682	$ (533)
Cash and cash equivalents at beginning of year	7,229	6,547	7,080
Cash and cash equivalents at end of year	$ 10,626	$ 7,229	$ 6,547

The information on pages 47 through 68 is an integral part of these statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Exxon Mobil Corporation.

The corporation's principal business is energy, involving the worldwide exploration, production, transportation and sale of crude oil and natural gas (upstream) and the manufacture, transportation and sale of petroleum products (downstream). The corporation is also a major worldwide manufacturer and marketer of petrochemicals (chemicals), and participates in electric power generation (upstream).

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Certain reclassifications to prior years have been made to conform to the 2003 presentation.

1. Summary of Accounting Policies

Principles of Consolidation. The consolidated financial statements include the accounts of those significant subsidiaries owned directly or indirectly with more than 50 percent of the voting rights held by the corporation, and for which other shareholders do not possess the right to participate in significant management decisions. They also include the corporation's share of the undivided interest in upstream assets and liabilities. Additionally, the corporation consolidates certain affiliates in which it has less than a majority ownership, because of guarantees or other arrangements that create majority economic interests in these affiliates which are greater than the corporation's voting interests.

Amounts representing the corporation's percentage interest in the underlying net assets of other significant subsidiaries and less than majority owned companies in which a significant equity ownership interest is held, are included in "Investments and advances"; the corporation's share of the net income of these companies is included in the consolidated statement of income caption "Income from equity affiliates." The corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in consolidated shareholder's equity. Evidence of loss in value that might indicate impairment, similar to that used for consolidated assets, occurring within companies accounted for on the equity method is assessed to determine if such evidence represents a long term reduction in value of the corporation's investment.

Revenue Recognition. The corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments. In all cases, revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectibility is reasonably assured.

Revenues from the production of natural gas properties in which the corporation has an interest with the other producers are recognized on the basis of the company's net working interest. Differences between actual production and net working interest volumes are not significant.

Derivative Instruments. The corporation makes limited use of derivatives. Derivative instruments are not held for trading purposes nor do they have leverage features. When the corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices. The gains and losses resulting from the changes in fair value of these instruments are recorded in income, except when the instruments are designated as hedging the currency exposure of net investments in foreign subsidiaries, in which case they are recorded in the cumulative foreign exchange translation account, as part of shareholders' equity.

The gains and losses on derivative instruments that are designated as fair value hedges (i.e., those hedging the exposure to changes in the fair value of an asset or a liability or the changes in the fair value of a firm commitment) are offset by the gains and losses from the changes in fair value of the hedged items, which are also recognized in income. Most of these designated hedges are entered into at the same time that the hedged items are transacted, they are fully effective and in combination with the offsetting hedged items, they result in no net impact on income. In some situations, the corporation has chosen not to designate certain immaterial derivatives used for hedging economic exposure as hedges for accounting purposes due to the excessive administrative effort that would be required to account for these items as hedging transactions. These derivatives are recorded on the balance sheet at fair value and the gains and losses arising from changes in fair value are recognized in income. All derivatives activity is immaterial.

Inventories. Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method — LIFO). Inventory costs include expenditures and other charges (including depreciation) directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. Inventories of materials and supplies are valued at cost or less.

Crude oil, products and merchandise as of year-end 2003 and 2002 consist of the following:

	2003	2002
	(billions of dollars)	
Petroleum products	$3.2	$2.9
Crude oil	2.2	1.9
Chemical products	1.9	1.7
Gas/other	0.4	0.3
Total	$7.7	$6.8

Property, Plant and Equipment. Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

The corporation uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory

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expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field.

The corporation continues to carry as an asset the cost of drilling exploratory wells that find sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure is made and drilling of additional exploratory wells is under way or firmly planned for the near future. Once exploration activities demonstrate that sufficient quantities of commercially producible reserves have been discovered, continued capitalization is dependent on project reviews, which take place at least annually, to ensure that satisfactory progress toward ultimate development of the reserves is being achieved. Exploratory well costs not meeting these criteria are charged to expense.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Significant unproved properties are assessed for impairment individually and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the corporation expects to hold the properties. The cost of properties that are not individually significant are aggregated by groups and amortized over the average holding period of the properties of the groups. The valuation allowances are reviewed at least annually. Other exploratory expenditures, including geophysical costs, other dry hole costs and annual lease rentals, are expensed as incurred.

Unit-of-production depreciation is applied to property, plant and equipment, including capitalized exploratory drilling and development costs, associated with productive depletable extractive properties, all in the upstream segment. Unit-of-production rates are based on proved developed reserves, which are oil, gas and other mineral reserves estimated to be recoverable from existing facilities using current operating methods. Additional oil and gas to be obtained through the application of improved recovery techniques is included when, or to the extent that, the requisite commercial-scale facilities have been installed and the required wells have been drilled.

Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain the corporation’s wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labor costs to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Gains on sales of proved and unproved properties are only recognized when there is no uncertainty about the recovery of costs applicable to any interest retained or where there is no substantial obligation for future performance by the corporation. Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

Proved oil and gas properties held and used by the corporation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated corporate plan investment evaluation assumptions for crude oil commodity prices and foreign currency exchange rates. Annual volumes are based on individual field production profiles which are also updated annually. Prices for natural gas and other products sold under contract are based on corporate plan assumptions developed annually by major region/contract and also for investment evaluation purposes. Cash flow estimates for impairment testing exclude derivative instruments.

Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. Impairments are measured by the amount the carrying value exceeds the fair value.

Asset Retirement Obligations and Environmental Costs. The corporation incurs retirement obligations for its upstream assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in present value. Asset retirement obligations are not recorded for downstream and chemicals facilities, because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties, and projected cash expenditures are not discounted.

Foreign Currency Translation. The “functional currency” for translating the accounts of the majority of downstream and chemicals operations outside the U.S. is the local currency. Local currency is also used for upstream operations that are relatively self-contained and integrated within a particular country, such as in Canada, the United Kingdom, Norway and continental Europe. The U.S. dollar is used for operations in highly inflationary economies, in Singapore which is predominantly export oriented, and for some upstream operations, primarily in Malaysia, Indonesia, Angola, Nigeria, Equatorial Guinea and the Middle East countries. For all operations, gains or losses on remeasuring foreign currency transactions into functional currency are included in income.

Stock Option Accounting. Effective January 1, 2003, the corporation adopted for all employee stock-based awards granted after that date, the recognition provisions of Statement of Financial Accounting Standards No. 123 (FAS 123), “Accounting for Stock-Based Compensation.” In accordance with FAS 123, compensation expense

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for awards granted on or after January 1, 2003 will be measured by the fair value of the award at the date of grant and recognized over the vesting period. The fair value of awards in the form of restricted stock is the market price of the stock. The fair value of awards in the form of stock options is estimated using an option-pricing model.

As permitted by FAS 123, the corporation has retained its prior method of accounting for stock-based awards granted before January 1, 2003. Under this method, compensation expense for awards granted in the form of stock options is measured at the intrinsic value of the options (the difference between the market price of stock and the exercise price of the options) on the date of grant. Since these two prices are the same on the date of grant, no compensation expense was recognized in income for these awards. Additionally, compensation expense for awards granted in the form of restricted stock is based on the price of the stock when it is granted and is recognized over the vesting period, which is the same method of accounting as under FAS 123.

If the provisions of FAS 123 had been adopted for all prior years, the impact on compensation expense, net income, and net income per share would have been as follows:

	2003	2002	2001
		(millions of dollars)	
Net income, as reported	$21,510	$11,460	$15,320
Add: Stock-based compensation, net of tax included in reported net income	86	19	8
Deduct: Stock-based compensation, net of tax determined under fair value based method	(93)	(180)	(293)
Pro forma net income	$21,503	$11,299	$15,035
		(dollars per share)	
Net income per share:			
Basic – as reported	$ 3.24	$ 1.69	$ 2.23
Basic – pro forma	3.24	1.67	2.19
Diluted – as reported	3.23	1.68	2.21
Diluted – pro forma	3.23	1.66	2.17

The pro forma amounts that would have been reported if FAS 123 had been in effect for all years are based on the fair value of stock-based awards granted for each of those years and recognized over the vesting period. In 2003 and 2002, the stock-based awards were in the form of restricted common stock and restricted stock units, and the fair value is based on the price of the stock at the date of grant, which was $36.11 and $34.64 in 2003 and 2002, respectively. No stock option awards were made in 2003 and 2002. In 2001, the stock-based awards were primarily stock options and the fair values were estimated using an option-pricing model. The average fair value for each stock option granted during 2001 was $6.89. The weighted average assumptions used to determine this amount for 2001 were: risk-free interest rate of 4.6 percent, expected life of 6 years, volatility of 16 percent and a dividend yield of 2.5 percent.

2. Accounting Change

As of January 1, 2003, the corporation adopted Financial Accounting Standards Board Statement of Financial Accounting Standards No. 143 (FAS 143), "Accounting for Asset Retirement Obligations." The primary impact of FAS 143 is to change the method of accruing for upstream site restoration costs. Asset retirement obligations are not recorded for downstream and chemicals facilities because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

Upstream costs were previously accrued ratably over the productive lives of the assets in accordance with Statement of Financial Accounting Standards No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies." At the end of 2002, the cumulative amount accrued under FAS 19 was approximately $3.5 billion. Under FAS 143, the fair values of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically at the time the assets are installed. Amounts recorded for the related assets will be increased by the amount of these obligations. Over time the liabilities will be accreted for the change in their present value and the initial capitalized costs will be depreciated over the useful lives of the related assets.

The cumulative adjustment for the change in accounting principle reported in the first quarter of 2003 was after-tax income of $550 million (net of $442 million of income tax effects, including ExxonMobil's share of related equity company income taxes of $51 million), or $0.08 per common share. The effect of this accounting change on the balance sheet was a $0.3 billion increase to property, plant and equipment, a $0.6 billion reduction to the accrued liability and a $0.4 billion increase in deferred income tax liabilities.

This adjustment is due to the difference in the method of accruing site restoration costs under FAS 143 compared with the method required by FAS 19, the accounting standard that the corporation has been required to follow since 1978. Under FAS 19, site restoration costs were accrued on a unit-of-production basis of accounting as the oil and gas is produced. The FAS 19 method matches the accruals with the revenues generated from production and results in most of the costs being accrued early in field life, when production is at the highest level. Because FAS 143 requires accretion of the liability as a result of the passage of time using an interest method of allocation, the majority of the costs will be accrued toward the end of field life, when production is at the lowest level. The cumulative income adjustment described above resulted from reversing the higher liability accumulated under FAS 19 in order to adjust it to the lower present value amount resulting from transition to FAS 143. This amount being reversed in transition, which was previously charged to operating earnings under FAS 19, will again be charged to those earnings under FAS 143 in future years.

If FAS 143 had been in effect in 2002, net income that would have been reported would not have been materially different from the net income that was reported under FAS 19. The effect of FAS 143 on net income in the current year period is also not material.

3. Discontinued Operations and Extraordinary Item

In 2002, the copper business in Chile and the coal operations in Colombia were sold. Earnings of these businesses are reported as discontinued operations for all years presented in the consolidated statement of income. Income taxes related to discontinued operations were: 2002 – $41 million and 2001 – $47 million. Included in discontinued operations for 2002 are gains on the dispositions of $400 million, net of tax. The assets that were sold were primarily property, plant and

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equipment in the amount of $1.3 billion. Revenues of these operations were not material. These businesses were historically reported in the "All Other" column in the segment disclosures located in note 19 on pages 66 and 67.

Net income for 2001 included net after-tax gains from asset management activities in the chemicals segment and regulatory required asset divestitures in the amount of $215 million (including an income tax credit of $21 million), or $0.03 per common share. These net after-tax gains were reported as extraordinary items according to accounting requirements for business combinations accounted for as pooling of interests.

4. Merger Expenses and Reorganization Reserves

In association with the merger between Exxon and Mobil, $410 million pre-tax ($275 million after-tax) and $748 million pre-tax ($525 million after-tax) of costs were recorded as merger-related expenses in 2002 and 2001, respectively. Cumulative charges for the period 1999 to 2002 of $3,189 million included separation expenses of approximately $1,460 million related to workforce reductions (approximately 8,200 employees at year-end 2002), plus implementation costs and merger closing costs. Reflecting the completion of merger-related activities, merger expenses were not reported in 2003.

The separation reserve balance at year-end 2003 of approximately $48 million is expected to be expended mainly in 2004.

The following table summarizes the activity in the reorganization reserves. The 2001 opening balance represents accruals for provisions taken in prior years.

	Opening Balance	Additions	Deductions	Balance at Year End
		(millions of dollars)		
2001	$ 339	$ 187	$ 329	$ 197
2002	197	93	189	101
2003	101	—	53	48

5. Miscellaneous Financial Information

Research and development costs totaled $618 million in 2003, $631 million in 2002 and $603 million in 2001.

Net income included aggregate foreign exchange transaction gains of $11 million in 2003, and losses of $106 million in 2002 and $142 million in 2001.

In 2003, 2002 and 2001, net income included gains of $255 million, $159 million and $238 million, respectively, attributable to the combined effects of LIFO inventory accumulations and draw-downs. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $6.8 billion and $6.8 billion at December 31, 2003 and 2002, respectively.

6. Cash Flow Information

The consolidated statement of cash flows provides information about changes in cash and cash equivalents. Highly liquid investments with maturities of three months or less when acquired are classified as cash equivalents.

In 2003, ExxonMobil completed a divestment of interests in shares of Ruhrgas AG, a German gas transmission company. These shares were held in part by BEB Erdgas und Erdoel GmbH (BEB), an investment accounted for by the equity method, and in part by a consolidated affiliate in Germany. In 2002, cash in the amount of $1,466 million was received from BEB, an equity company, and included in cash flows from operating activities (see Ruhrgas transaction line on Statement of Cash Flows, page 46). This cash from BEB was a loan and was part of a restructuring that enabled BEB to transfer its holdings in Ruhrgas AG provided regulatory approval was received. No income was recorded in 2002.

In 2003, upon receipt of regulatory approvals, the Ruhrgas AG shares held by BEB were transferred, cash was received for the shares held by the consolidated affiliate and a one-time gain of $1,700 million after tax was recognized in net income. The $2,240 million reduction in 2003 cash flow from operating activities reflects the pre-tax gains from the transaction. The cash generated from these gains for the BEB portion of the transaction was reported in 2002. For the shares held by the consolidated affiliate, the cash received was reported in cash flows from investing activities in 2003.

Cash payments for interest were: 2003 – $429 million, 2002 – $437 million and 2001 – $562 million. Cash payments for income taxes were: 2003 – $8,149 million, 2002 – $6,106 million and 2001 – $9,855 million.

7. Additional Working Capital Information

	Dec. 31 2003	Dec. 31 2002
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $358 million and $314 million	$16,766	$15,317
Other, less reserves of $38 million and $39 million	7,543	5,846
Total	$24,309	$21,163
Notes and loans payable		
Bank loans	$ 972	$ 987
Commercial paper	1,579	1,870
Long-term debt due within one year	1,903	884
Other	335	352
Total	$ 4,789	$ 4,093
Accounts payable and accrued liabilities		
Trade payables	$15,334	$13,792
Payables to equity companies	1,584	1,192
Accrued taxes other than income taxes	5,374	4,628
Other	6,153	5,574
Total	$28,445	$25,186

On December 31, 2003, unused credit lines for short-term financing totaled approximately $4.3 billion. Of this total, $2.6 billion support commercial paper programs under terms negotiated when drawn. The weighted average interest rate on short-term borrowings outstanding at December 31, 2003 and 2002 was 2.9 percent and 2.8 percent, respectively.

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8. Equity Company Information

The summarized financial information below includes amounts related to certain less than majority owned companies and majority owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see note 1). These companies are primarily engaged in crude production, natural gas marketing and refining operations in North America; natural gas production, natural gas distribution, and downstream operations in Europe; crude production in Kazakhstan and Abu Dhabi and LNG operations in Qatar. Also included are several power generation, petrochemical/lubes manufacturing and chemical ventures. The corporation's ownership in these ventures is in the form of shares in corporate joint ventures as well as interests in partnerships. The share of total revenues in the table below representing sales to ExxonMobil consolidated companies was 18 percent, 19 percent and 19 percent, respectively, in the years 2003, 2002 and 2001.

	2003		2002		2001	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	$63,651	$ 23,667	$47,204	$ 17,230	$47,072	$ 17,520
Income before income taxes	$11,432	$ 5,356	$ 6,028	$ 2,844	$ 6,952	$ 2,922
Less: Related income taxes	(1,871)	(983)	(1,461)	(778)	(1,562)	(748)
Income from operations	$ 9,561	$ 4,373	$ 4,567	$ 2,066	$ 5,390	$ 2,174
Cumulative effect of accounting change, net of income tax	74	35	—	—	—	—
Net income	$ 9,635	$ 4,408	$ 4,567	$ 2,066	$ 5,390	$ 2,174
Current assets	$19,334	$ 7,386	$20,162	$ 7,658	$18,992	$ 7,369
Property, plant and equipment, less accumulated depreciation	40,895	15,034	39,351	14,254	36,565	13,135
Other long-term assets	5,820	2,694	5,524	2,614	5,127	2,284
Total assets	$66,049	$ 25,114	$65,037	$ 24,526	$60,684	$ 22,788
Short-term debt	$ 3,402	$ 1,336	$ 3,561	$ 1,443	$ 3,142	$ 1,232
Other current liabilities	13,394	5,112	15,529	5,991	16,218	6,349
Long-term debt	7,997	2,815	9,236	3,352	10,496	3,950
Other long-term liabilities	6,738	3,215	8,248	3,881	6,253	2,862
Advances from shareholders	11,092	3,091	10,721	2,927	8,443	2,179
Net assets	$23,426	$ 9,545	$17,742	$ 6,932	$16,132	$ 6,216

In December 2003, the Financial Accounting Standards Board issued a revised Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities," replacing the original interpretation issued in January 2003. FIN 46 provides guidance on when certain entities should be consolidated or the interests in those entities should be disclosed by enterprises that do not control them through majority voting interest. Under FIN 46, entities are required to be consolidated by enterprises that lack majority voting interest when equity investors of those entities have insignificant capital at risk or they lack voting rights, the obligation to absorb expected losses, or the right to receive expected returns. Entities identified with these characteristics are called variable interest entities and the interests that enterprises have in these entities are called variable interests. These interests can derive from certain guarantees, leases, loans or other arrangements that result in risks and rewards that are disproportionate to the voting interests in the entities.

The provisions of FIN 46 must be immediately applied for variable interest entities created after January 31, 2003 and for variable interests in entities commonly referred to as "special purpose entities." For all other variable interest entities, implementation is required by March 31, 2004.

There have been no variable interest entities created after January 31, 2003 in which the corporation has an interest. The corporation identified three operating entities in which the corporation has variable interests primarily through lease commitments and certain guarantees extended by the corporation. The corporation chose to implement FIN 46 in the fourth quarter 2003 by consolidating these entities, which were previously accounted for under the equity method. There was no effect on net income, because the corporation was already recording its share of net income of these entities. The impact to the balance sheet was to increase both assets and liabilities by about $500 million. However, there was no change to the calculation of return on average capital employed, because the corporation already includes its share of equity company debt in the determination of average capital employed.

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9. Investments and Advances

	Dec. 31 2003	Dec. 31 2002
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	$ 9,545	$ 6,932
Advances	3,091	2,927
	$12,636	$ 9,859
Companies carried at cost or less and stock investments carried at fair value	1,795	1,088
	$14,431	$10,947
Long-term receivables and miscellaneous investments at cost or less	1,104	1,164
Total	$15,535	$12,111

10. Property, Plant and Equipment and Asset Retirement Obligations

	Dec. 31, 2003		Dec. 31, 2002	
Property, Plant and Equipment	**Cost**	**Net**	**Cost**	**Net**
	(millions of dollars)			
Upstream	$138,701	$ 58,727	$122,210	$51,696
Downstream	59,939	29,566	54,032	26,920
Chemicals	20,623	10,115	19,138	9,909
Other	10,052	6,557	9,580	6,415
Total	$229,315	$104,965	$204,960	$94,940

In the upstream segment, depreciation is on a unit-of-production basis and so depreciable life will vary by field. In the downstream segment, investments in refinery and lubes basestock manufacturing facilities are generally depreciated on a straight-line basis over a 25-year life and service station buildings and fixed improvements over a 20-year life. In the chemicals segment, investments in process equipment are generally depreciated on a straight-line basis over a 20-year life.

Accumulated depreciation and depletion totaled $124,350 million at the end of 2003 and $110,020 million at the end of 2002. Interest capitalized in 2003, 2002 and 2001 was $490 million, $426 million and $518 million, respectively.

Mineral Interests

Statements of Financial Accounting Standards No. 141 (FAS 141), “Business Combinations,” and No. 142 (FAS 142), “Goodwill and Other Intangible Assets,” were issued by the Financial Accounting Standards Board (FASB) in June 2001 and became effective for the corporation on July 1, 2001 and January 1, 2002, respectively. Currently, the Emerging Issues Task Force (EITF) is considering the issue of whether FAS 141 and 142 require interests held under oil, gas and mineral leases to be separately classified as intangible assets on the balance sheets of companies in the extractive industries. If such interests were deemed to be intangible assets by the EITF, mineral rights to extract oil and gas for both undeveloped and developed leaseholds would be classified separately from oil and gas properties as intangible assets on the corporation’s balance sheet. Historically the corporation has capitalized the cost of oil and gas leasehold interests in accordance with statement of Financial Accounting Standard No. 19 (FAS 19), “Financial Accounting and Reporting by Oil and Gas Producing Companies.” Also, consistent with industry practice, the corporation has reported these assets as part of tangible oil and gas property, plant and equipment.

This interpretation of FAS 141 and 142 would only affect the classification of oil and gas leaseholds on the corporation’s balance sheet, and would not affect total assets, net worth or cash flows. The corporation’s results of operations would not be affected, since these leasehold costs would continue to be amortized in accordance with FAS 19. The amount that is subject to reclassification as of December 31, 2003 was $4.5 billion, and as of December 31, 2002 was $4.6 billion.

The following table summarizes the activity in the liability for asset retirement obligations:

Asset Retirement Obligations	**2003**
	(millions of dollars)
Beginning balance	$ 3,454
Cumulative effect of accounting change	(622)
Accretion expense and other provisions	174
Payments made	(113)
Liabilities incurred	253
Foreign currency translation/other	294
Ending balance	$ 3,440

Cumulative Effect of Accounting Change	**2003**
	(millions of dollars)
Increase in net PP&E	$ 284
Decrease in ARO liability	622
Increase in deferred tax liability	(391)
Increase in investments in equity companies	35
Total after-tax earnings	$ 550

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11. Leased Facilities

At December 31, 2003, the corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum lease commitments as indicated in the table.

Net rental expenditures for 2003, 2002 and 2001 totaled $2,298 million, $2,322 million and $2,454 million, respectively, after being reduced by related rental income of $141 million, $140 million and $199 million, respectively. Minimum rental expenditures totaled $2,319 million in 2003, $2,378 million in 2002 and $2,562 million in 2001.

	Minimum Commitment	Related Rental Income
	(millions of dollars)	
2004	$ 1,299	$ 51
2005	988	37
2006	732	32
2007	539	29
2008	471	19
2009 and beyond	2,160	110
Total	$ 6,189	$ 278

12. Employee Stock Ownership Plans

In 1989, the Exxon and Mobil employee stock ownership plan trusts borrowed $1,000 million and $800 million, respectively, to finance the purchase of shares of Exxon and Mobil stock. The trusts were merged in late 1999 to create the ExxonMobil leveraged employee stock ownership trust (ExxonMobil ESOP). The ExxonMobil ESOP is a constituent part of the ExxonMobil Savings Plan, which, effective February 8, 2002, is an employee stock ownership plan in its entirety.

Employees eligible to participate in the ExxonMobil Savings Plan may elect to participate in the ExxonMobil ESOP. Corporate contributions to the plan and dividends were used to make principal and interest payments on the ExxonMobil ESOP notes ($65 million outstanding as of December 31, 2002, which was fully repaid in 2003). As corporate contributions and dividends were credited, common shares were allocated to participants' plan accounts. The corporation's contribution to the ExxonMobil ESOP, representing the amount by which debt service exceeded dividends on shares held by the ExxonMobil ESOP, was $59 million, $86 million and $58 million in 2003, 2002 and 2001, respectively.

Accounting for the plans has followed the principles that were in effect for the respective plans when they were established. During the time that the guaranteed ESOP borrowing was outstanding, the borrowing was included in ExxonMobil's debt. The future compensation to be earned by employees was classified in Shareholders' Equity. No guaranteed debt was outstanding at year-end 2003 and there was no future compensation classified in Shareholders' Equity as all compensation was earned. Expense, net of the dividends used for debt service, was recognized as the debt was repaid and shares were earned by employees. The amount of compensation expense related to the plans and recorded by the corporation during the periods was $32 million in 2003, $122 million in 2002 and $83 million in 2001.

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13. Capital

On May 30, 2001, the company's Board of Directors approved a two-for-one stock split of common stock for shareholders of record on June 20, 2001. The authorized common stock was increased from 4.5 billion shares without par value to 9 billion shares without par value, and the issued shares were split on a two-for-one basis on June 20, 2001.

In 1989, $1,800 million of benefit related balances were recorded as debt and as a reduction to shareholders' equity, representing Exxon and Mobil guaranteed borrowings by the Exxon ESOP to purchase Exxon Class A Preferred Stock and the Mobil ESOP to purchase Mobil Class B Preferred Stock. All preferred shares were converted to ExxonMobil common stock by year-end 1999. As common shares were earned by employees and the debt was repaid, the benefit plan related balances were reduced. No guaranteed debt was outstanding at year-end 2003 and there was no future compensation classified in shareholders' equity as all compensation was earned.

The table below summarizes the earnings per share calculations.

Net income per common share	**2003**	**2002**	**2001**
Income from continuing operations *(millions of dollars)*	$20,960	$11,011	$15,003
Weighted average number of common shares outstanding *(millions of shares)*	6,634	6,753	6,868
Net income per common share *(dollars)*			
Income from continuing operations	$ 3.16	$ 1.62	$ 2.19
Discontinued operations, net of income tax	—	0.07	0.01
Extraordinary gain, net of income tax	—	—	0.03
Cumulative effect of accounting change, net of income tax	0.08	—	—
Net income	$ 3.24	$ 1.69	$ 2.23
Net income per common share – assuming dilution			
Income from continuing operations *(millions of dollars)*	$20,960	$11,011	$15,003
Adjustment for assumed dilution	—	—	(4)
Income available to common shares	$20,960	$11,011	$14,999
Weighted average number of common shares outstanding *(millions of shares)*	6,634	6,753	6,868
Effect of employee stock-based awards	28	50	73
Weighted average number of common shares outstanding – assuming dilution	6,662	6,803	6,941
Net income per common share *(dollars)*			
Income from continuing operations	$ 3.15	$ 1.61	$ 2.17
Discontinued operations, net of income tax	—	0.07	0.01
Extraordinary gain, net of income tax	—	—	0.03
Cumulative effect of accounting change, net of income tax	0.08	—	—
Net income	$ 3.23	$ 1.68	$ 2.21
Dividends paid per common share *(dollars)*	$ 0.98	$ 0.92	$ 0.91

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14. Financial Instruments and Derivatives

The fair value of financial instruments is determined by reference to various market data and other valuation techniques as appropriate. Long-term debt is the only category of financial instruments whose fair value differs materially from the recorded book value. The estimated fair value of total long-term debt, including capitalized lease obligations, at December 31, 2003 and 2002, was $5.6 billion and $7.8 billion, respectively, as compared to recorded book values of $4.8 billion and $6.7 billion.

The corporation's size, geographic diversity and the complementary nature of the upstream, downstream and chemicals businesses mitigate the corporation's risk from changes in interest rates, currency rates and commodity prices. The corporation relies on these operating attributes and strengths to reduce enterprise-wide risk. As a result, the corporation makes limited use of derivatives to offset exposures arising from existing transactions.

The corporation does not trade in derivatives nor does it use derivatives with leveraged features. The corporation maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity. The corporation's derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity. Interest rate, foreign exchange rate and commodity price exposures arising from derivative contracts undertaken in accordance with the corporation's policies have not been significant.

The fair value of derivatives outstanding and recorded on the balance sheet was a net payable of $17 million and a net receivable of $20 million at year-end 2003 and 2002, respectively. This is the amount that the corporation would have paid to or received from third parties if these derivatives had been settled. These derivative fair values were substantially offset by the fair values of the underlying exposures being hedged. The corporation recognized a gain of $4 million, a loss of $35 million and a gain of $23 million related to derivative activity during 2003, 2002 and 2001, respectively. The gains/losses included the offsetting amounts from the changes in fair value of the items being hedged by the derivatives.

15. Long-Term Debt

At December 31, 2003, long-term debt consisted of $4,333 million due in U.S. dollars and $423 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $1,903 million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing, together with sinking fund payments required, in each of the four years after December 31, 2004, in millions of dollars, are: 2005 – $363, 2006 – $136, 2007 – $104 and 2008 –$274. Certain of the borrowings described may from time to time be assigned to other ExxonMobil affiliates. At December 31, 2003, the corporation's unused long-term credit lines were not material.

There was no outstanding balance of defeased debt at year-end 2003. Summarized long-term borrowings at year-end 2003 and 2002 were as shown in the adjacent table:

	2003	2002
	(millions of dollars)	
Exxon Mobil Corporation		
Guaranteed zero coupon notes due 2004		
– Net of unamortized discount	$ —	$ 933
Exxon Capital Corporation (1)		
6.0% Guaranteed notes due 2005	106	106
6.125% Guaranteed notes due 2008	160	160
SeaRiver Maritime Financial Holdings, Inc. (1)		
Guaranteed debt securities due 2005-2011 (2)	85	95
Guaranteed deferred interest debentures due 2012		
– Face value net of unamortized discount plus accrued interest	1,121	1,006
Imperial Oil Limited		
Variable rate notes due 2004 (3)	—	600
Variable rate Canadian dollar notes due 2004 (4)	—	317
ExxonMobil Canada Ltd.		
5.0% U.S. dollar Eurobonds due 2004	—	255

Mobil Producing Nigeria Unlimited		
8.625% notes due 2006	63	104
Mobil Corporation		
8.625% debentures due 2021	248	248
7.625% debentures due 2033	—	204
Industrial revenue bonds due 2007-2033 (5)	1,688	1,530
Other U.S. dollar obligations (6)	640	507
Other foreign currency obligations	275	296
Capitalized lease obligations (7)	370	294
Total long-term debt	$4,756	$6,655

(1) Additional information is provided for these subsidiaries on pages 56 to 60.

(2) Average effective interest rate of 1.2% in 2003 and 1.8% in 2002.

(3) Average effective interest rate of 1.9% in 2002.

(4) Average effective interest rate of 2.8% in 2002.

(5) Average effective interest rate of 1.7% in 2003 and 1.8% in 2002.

(6) Average effective interest rate of 6.3% in 2003 and 5.7% in 2002.

(7) Average imputed interest rate of 7.0% in 2003 and 6.4% in 2002.

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

Exxon Mobil Corporation has fully and unconditionally guaranteed the 6.0% notes due 2005 ($106 million of long-term debt at year-end 2003) and the 6.125% notes due 2008 ($160 million) of Exxon Capital Corporation and the deferred interest debentures due 2012 ($1,121 million) and the debt securities due 2005-2011 ($85 million long-term and $10 million short-term) of SeaRiver Maritime Financial Holdings, Inc. Exxon Capital Corporation and SeaRiver Maritime Financial Holdings, Inc. are 100 percent owned subsidiaries of Exxon Mobil Corporation.

The following condensed consolidating financial information is provided for Exxon Mobil Corporation, as guarantor, and for Exxon Capital Corporation and SeaRiver Maritime Financial Holdings, Inc., as issuers, as an alternative to providing separate financial statements for the issuers. The accounts of Exxon Mobil Corporation, Exxon Capital Corporation and SeaRiver Maritime Financial Holdings, Inc. are presented utilizing the equity method of accounting for investments in subsidiaries.

	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
				(millions of dollars)		
Condensed consolidated statement of income for twelve months ended December 31, 2003						
Revenues and other income						
Sales and other operating revenue, including excise taxes	$ 11,328	$ —	$ —	$ 225,726	$ —	$ 237,054
Income from equity affiliates	18,163	—	1	4,363	(18,154)	4,373
Other income	3,229	—	—	2,082	—	5,311
Intercompany revenue	17,918	33	19	142,930	(160,900)	—
Total revenues and other income	50,638	33	20	375,101	(179,054)	246,738
Costs and other deductions						
Crude oil and product purchases	17,342	—	—	240,908	(150,592)	107,658
Production and manufacturing expenses	6,492	2	1	19,691	(4,926)	21,260
Selling, general and administrative expenses	2,037	2	—	11,526	(169)	13,396
Depreciation and depletion	1,535	5	2	7,505	—	9,047
Exploration expenses, including dry holes	247	—	—	763	—	1,010
Merger related expenses	—	—	—	—	—	—
Interest expense	648	21	121	4,629	(5,212)	207
Excise taxes	1	—	—	23,854	—	23,855
Other taxes and duties	9	—	—	37,636	—	37,645
Income applicable to minority and preferred interests	—	—	—	694	—	694
Total costs and other deductions	28,311	30	124	347,206	(160,899)	214,772
Income before income taxes	22,327	3	(104)	27,895	(18,155)	31,966
Income taxes	1,367	(1)	(37)	9,677	—	11,006
Income from continuing operations	20,960	4	(67)	18,218	(18,155)	20,960
Discontinued operations, net of income tax	—	—	—	—	—	—
Extraordinary gain, net of income tax	—	—	—	—	—	—
Accounting change, net of income tax	550	—	—	481	(481)	550

Net income	$ 21,510	$ 4	$ (67)	$ 18,699	$ (18,636)	$ 21,510

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	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
				(millions of dollars)		
Condensed consolidated statement of income for twelve months ended December 31, 2002						
Revenues and other income						
Sales and other operating revenue, including excise taxes	$ 8,711	$ —	$ —	$ 192,238	$ —	$ 200,949
Income from equity affiliates	10,177	—	(16)	2,048	(10,143)	2,066
Other income	580	5	—	906	—	1,491
Intercompany revenue	15,711	41	27	120,836	(136,615)	—
Total revenues and other income	35,179	46	11	316,028	(146,758)	204,506
Costs and other deductions						
Crude oil and product purchases	14,687	—	—	207,709	(131,446)	90,950
Production and manufacturing expenses	5,312	2	1	16,839	(4,323)	17,831
Selling, general and administrative expenses	1,592	2	—	10,898	(136)	12,356
Depreciation and depletion	1,572	5	3	6,730	—	8,310
Exploration expenses, including dry holes	147	—	—	773	—	920
Merger related expenses	70	—	—	356	(16)	410
Interest expense	655	22	112	4,634	(5,025)	398
Excise taxes	—	—	—	22,040	—	22,040
Other taxes and duties	12	—	—	33,560	—	33,572
Income applicable to minority and preferred interests	—	—	—	209	—	209
Total costs and other deductions	24,047	31	116	303,748	(140,946)	186,996
Income before income taxes	11,132	15	(105)	12,280	(5,812)	17,510
Income taxes	121	6	(31)	6,403	—	6,499
Income from continuing operations	11,011	9	(74)	5,877	(5,812)	11,011
Discontinued operations, net of income tax	449	—	—	456	(456)	449
Extraordinary gain, net of income tax	—	—	—	—	—	—
Accounting change, net of income tax	—	—	—	—	—	—
Net income	$ 11,460	$ 9	$ (74)	$ 6,333	$ (6,268)	$ 11,460
Condensed consolidated statement of income for twelve months ended December 31, 2001						
Revenues and other income						
Sales and other operating revenue, including excise taxes	$ 28,800	$ —	$ —	$ 179,915	$ —	$ 208,715
Income from equity affiliates	13,094	—	32	2,145	(13,097)	2,174
Other income	333	—	—	1,563	—	1,896
Intercompany revenue	6,252	584	62	106,498	(113,396)	—
Total revenues and other income	48,479	584	94	290,121	(126,493)	212,785

Costs and other deductions						
Crude oil and product purchases	19,483	—	—	174,455	(101,681)	92,257
Production and manufacturing expenses	5,696	3	1	17,192	(5,149)	17,743
Selling, general and administrative expenses	2,158	2	—	10,800	(62)	12,898
Depreciation and depletion	1,584	5	3	6,256	—	7,848
Exploration expenses, including dry holes	125	—	—	1,050	—	1,175
Merger related expenses	89	—	—	771	(112)	748
Interest expense	1,043	531	114	4,924	(6,319)	293
Excise taxes	1,957	—	—	19,950	—	21,907
Other taxes and duties	14	—	—	33,363	—	33,377
Income applicable to minority and preferred interests	—	—	—	569	—	569
Total costs and other deductions	32,149	541	118	269,330	(113,323)	188,815
Income before income taxes	16,330	43	(24)	20,791	(13,170)	23,970
Income taxes	1,327	15	(20)	7,645	—	8,967
Income from continuing operations	15,003	28	(4)	13,146	(13,170)	15,003
Discontinued operations, net of income tax	102	—	—	108	(108)	102
Extraordinary gain, net of income tax	215	—	—	—	—	215
Accounting change, net of income tax	—	—	—	—	—	—
Net income	$ 15,320	$ 28	$ (4)	$ 13,254	$ (13,278)	$ 15,320

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
				(millions of dollars)		
Condensed consolidated balance sheet for year ended December 31, 2003						
Cash and cash equivalents	$ 5,647	$ —	$ —	$ 4,979	$ —	$ 10,626
Notes and accounts receivable – net	5,781	—	—	18,528	—	24,309
Inventories	1,027	—	—	7,930	—	8,957
Prepaid taxes and expenses	91	—	—	1,977	—	2,068
Total current assets	12,546	—	—	33,414	—	45,960
Investments and advances	126,568	—	401	357,104	(468,538)	15,535
Property, plant and equipment – net	16,733	98	1	88,133	—	104,965
Other long-term assets	1,714	—	105	5,999	—	7,818
Intercompany receivables	9,463	1,114	1,540	381,683	(393,800)	—
Total assets	$ 167,024	$ 1,212	$ 2,047	$ 866,333	$ (862,338)	$ 174,278
Notes and loans payable	$ 1,104	$ —	$ 10	$ 3,675	$ —	$ 4,789
Accounts payable and accrued liabilities	3,538	6	—	24,901	—	28,445
Income taxes payable	1,457	—	—	3,695	—	5,152
Total current liabilities	6,099	6	10	32,271	—	38,386
Long-term debt	261	266	1,206	3,023	—	4,756
Deferred income tax liabilities	3,643	29	296	16,150	—	20,118
Other long-term liabilities	3,991	16	—	17,096	—	21,103
Intercompany payables	63,115	106	382	330,197	(393,800)	—
Total liabilities	77,109	423	1,894	398,737	(393,800)	84,363
Earnings reinvested	115,956	4	(241)	72,012	(71,775)	115,956
Other shareholders' equity	(26,041)	785	394	395,584	(396,763)	(26,041)
Total shareholders' equity	89,915	789	153	467,596	(468,538)	89,915
Total liabilities and shareholders' equity	$ 167,024	$ 1,212	$ 2,047	$ 866,333	$ (862,338)	$ 174,278
Condensed consolidated balance sheet for year ended December 31, 2002						
Cash and cash equivalents	$ 710	$ —	$ —	$ 6,519	$ —	$ 7,229
Notes and accounts receivable – net	3,827	—	—	17,336	—	21,163
Inventories	964	—	—	7,104	—	8,068
Prepaid taxes and expenses	65	—	—	1,766	—	1,831
Total current assets	5,566	—	—	32,725	—	38,291
Investments and advances	101,694	—	400	336,061	(426,044)	12,111
Property, plant and equipment – net	16,922	104	3	77,911	—	94,940
Other long-term assets	2,421	—	121	4,760	—	7,302
Intercompany receivables	16,234	1,395	1,490	295,909	(315,028)	—

Total assets	$ 142,837	$ 1,499	$ 2,014	$ 747,366	$ (741,072)	$ 152,644
Notes and loans payable	$ —	$ 6	$ 10	$ 4,077	$ —	$ 4,093
Accounts payable and accrued liabilities	2,844	6	—	22,336	—	25,186
Income taxes payable	916	1	—	2,979	—	3,896
Total current liabilities	3,760	13	10	29,392	—	33,175
Long-term debt	1,311	266	1,101	3,977	—	6,655
Deferred income tax liabilities	3,163	31	301	12,989	—	16,484
Other long-term liabilities	5,820	—	—	15,913	—	21,733
Intercompany payables	54,186	290	382	260,170	(315,028)	—
Total liabilities	68,240	600	1,794	322,441	(315,028)	78,047
Earnings reinvested	100,961	93	(174)	54,547	(54,466)	100,961
Other shareholders' equity	(26,364)	806	394	370,378	(371,578)	(26,364)
Total shareholders' equity	74,597	899	220	424,925	(426,044)	74,597
Total liabilities and shareholders' equity	$ 142,837	$ 1,499	$ 2,014	$ 747,366	$ (741,072)	$ 152,644

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	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Condensed consolidated statement of cash flows for twelve months ended December 31, 2003						
Cash provided by/(used in) operating activities	$ 4,797	$ 23	$ 60	$ 24,945	$ (1,327)	$ 28,498
Cash flows from investing activities						
Additions to property, plant and equipment	(1,691)	—	—	(11,168)	—	(12,859)
Sales of long-term assets	238	—	—	2,052	—	2,290
Net intercompany investing	13,555	281	(50)	(13,523)	(263)	—
All other investing, net	—	—	—	(273)	—	(273)
Net cash provided by/(used in) investing activities	12,102	281	(50)	(22,912)	(263)	(10,842)
Cash flows from financing activities						
Additions to short- and long-term debt	—	—	—	842	—	842
Reductions in short- and long-term debt	—	—	—	(2,644)	—	(2,644)
Additions/(reductions) in debt with less than 90 day maturity	—	(6)	(10)	(306)	—	(322)
Cash dividends	(6,515)	(93)	—	(1,234)	1,327	(6,515)
Common stock acquired	(5,881)	—	—	—	—	(5,881)
Net intercompany financing activity	—	(184)	—	(58)	242	—
All other financing, net	434	(21)	—	(677)	21	(243)
Net cash provided by/(used in) financing activities	(11,962)	(304)	(10)	(4,077)	1,590	(14,763)
Effects of exchange rate changes on cash	—	—	—	504	—	504
Increase/(decrease) in cash and cash equivalents	$ 4,937	$ —	$ —	$ (1,540)	$ —	$ 3,397
Condensed consolidated statement of cash flows for twelve months ended December 31, 2002						
Cash provided by/(used in) operating activities	$ 1,970	$ 17	$ 69	$ 19,905	$ (693)	$ 21,268
Cash flows from investing activities						
Additions to property, plant and equipment	(1,727)	—	—	(9,710)	—	(11,437)
Sales of long-term assets	168	—	—	2,625	—	2,793
Net intercompany investing	9,640	(30)	(59)	(9,646)	95	—
All other investing, net	—	—	—	(1,114)	—	(1,114)
Net cash provided by/(used in) investing activities	8,081	(30)	(59)	(17,845)	95	(9,758)
Cash flows from financing activities						
Additions to short- and long-term debt	—	—	—	1,147	—	1,147
Reductions in short- and long-term debt	—	—	(10)	(1,163)	—	(1,173)

Additions/(reductions) in debt with less than 90 day maturity	—	(29)	—	(252)	—	(281)
Cash dividends	(6,217)	—	—	(693)	693	(6,217)
Common stock acquired	(4,798)	—	—	—	—	(4,798)
Net intercompany financing activity	—	42	—	53	(95)	—
All other financing, net	299	—	—	(330)	—	(31)
Net cash provided by/(used in) financing activities	(10,716)	13	(10)	(1,238)	598	(11,353)
Effects of exchange rate changes on cash	—	—	—	525	—	525
Increase/(decrease) in cash and cash equivalents	$ (665)	$ —	$ —	$ 1,347	$ —	$ 682

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Condensed consolidated statement of cash flows for twelve months ended December 31, 2001						
Cash provided by/(used in) operating activities	$ 7,277	$ 12	$ 113	$ 16,239	$ (752)	$ 22,889
Cash flows from investing activities						
Additions to property, plant and equipment	(2,058)	—	—	(7,931)	—	(9,989)
Sales of long-term assets	536	—	—	542	—	1,078
Net intercompany investing	3,152	17,759	(76)	(1,345)	(19,490)	—
All other investing, net	(31)	—	—	731	—	700
Net cash provided by/(used in) investing activities	1,599	17,759	(76)	(8,003)	(19,490)	(8,211)
Cash flows from financing activities						
Additions to short- and long-term debt	—	—	—	1,252	—	1,252
Reductions in short- and long-term debt	(62)	(15)	(7)	(1,634)	—	(1,718)
Additions/(reductions) in debt with less than 90 day maturity	—	(39)	—	(2,267)	—	(2,306)
Cash dividends	(6,254)	—	—	(752)	752	(6,254)
Common stock acquired	(5,721)	—	—	—	—	(5,721)
Net intercompany financing activity	—	(17,717)	(30)	(1,743)	19,490	—
All other financing, net	301	—	—	(595)	—	(294)
Net cash provided by/(used in) financing activities	(11,736)	(17,771)	(37)	(5,739)	20,242	(15,041)
Effects of exchange rate changes on cash	—	—	—	(170)	—	(170)
Increase/(decrease) in cash and cash equivalents	$ (2,860)	$ —	$ —	$ 2,327	$ —	$ (533)

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16. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the corporation and those affiliates at least 50 percent owned. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited or expire, or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Shares available for granting under the 2003 Incentive Program were 210,122 thousand at the end of 2003.

As under earlier programs, options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. Most of the options and SARs normally first become exercisable one year following the date of grant.

In 2001, stock options were granted under the 1993 Incentive Program. A small number of SARs also were granted to employees outside the U.S. In 2003 and 2002, no stock options or SARs were granted. Instead, long-term incentive awards totaling 10,381 and 11,072 thousand shares of restricted common stock and restricted common stock units were granted in 2003 and 2002, respectively. These shares with a value of $357 million and $361 million at the grant date in 2003 and 2002, respectively, will be issued to employees from treasury stock. The price of the stock on the date of grant was $36.11 and $34.64 in 2003 and 2002, respectively. The total compensation expense of $375 million for 2003 grants (including units with a value of $18 million that will be settled in cash) and of $384 million for 2002 grants (including units with a value of $23 million that will be settled in cash) will be recognized over the vesting period. During the applicable restricted periods, the shares may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares in each award vesting after three years and the remaining 50 percent vesting after seven years. A small number of awards granted to certain employees have longer vesting periods.

The following table summarizes information about restricted stock and restricted stock units, including those shares from former Mobil plans (shares in thousands):

Restricted Stock and Units	2003	2002	2001
Granted	10,381	11,072	348
Issued and outstanding at end of year	13,089	2,382	2,559

Changes that occurred in stock options in 2003, 2002 and 2001, including the former Mobil plans, are summarized below (shares in thousands):

	2003		2002		2001	
Stock Options	Shares	Avg. Exercise Price	Shares	Avg. Exercise Price	Shares	Avg. Exercise Price
Outstanding at beginning of year	246,995	$ 31.59	265,695	$ 30.54	248,680	$ 28.70
Granted	—	—	—	—	34,717	37.12
Exercised	(22,757)	16.80	(18,334)	16.18	(16,949)	16.63
Expired/canceled	(488)	35.86	(366)	40.47	(753)	39.44
Outstanding at end of year	223,750	33.09	246,995	31.59	265,695	30.54
Exercisable at end of year	222,054	33.06	243,548	31.46	221,405	29.29

The following table summarizes information about stock options outstanding, including those from former Mobil plans, at December 31, 2003 (shares in thousands):

	Options Outstanding			Options Exercisable	
Exercise Price Range	Shares	Avg. Remaining Contractual Life	Avg. Exercise Price	Shares	Avg. Exercise Price
$15.12-21.78	36,227	1.9 years	$ 18.41	36,227	$ 18.41

23.10-31.70	66,346	4.1 years	27.51	66,346	27.51
36.18-45.22	121,177	6.6 years	40.53	119,481	40.57
Total	223,750	5.1 years	33.09	222,054	33.06

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17. Litigation and Other Contingencies

Litigation

A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits and tax disputes. The corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. The corporation does not record liabilities when the likelihood that the liability has been incurred is probable, but the amount cannot be reasonably estimated, or when the liability is believed to be only reasonably possible or remote. ExxonMobil will continue to defend itself vigorously in these matters. Based on a consideration of all relevant facts and circumstances, the corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a materially adverse effect upon the corporation's operations or financial condition.

A number of lawsuits, including class actions, were brought in various courts against Exxon Mobil Corporation and certain of its subsidiaries relating to the accidental release of crude oil from the tanker Exxon Valdez in 1989. The vast majority of the compensatory claims have been resolved. All of the punitive damage claims were consolidated in the civil trial that began in May 1994.

In that trial, on September 24, 1996, the United States District Court for the District of Alaska entered a judgment in the amount of $5 billion in punitive damages to a class composed of all persons and entities who asserted claims for punitive damages from the corporation as a result of the Exxon Valdez grounding. ExxonMobil appealed the judgment. On November 7, 2001, the United States Court of Appeals for the Ninth Circuit vacated the punitive damage award as being excessive under the Constitution and remanded the case to the District Court for it to determine the amount of the punitive damage award consistent with the Ninth Circuit's holding. The Ninth Circuit upheld the compensatory damage award which has been paid. On December 6, 2002, the District Court reduced the punitive damage award from $5 billion to $4 billion. Both the plaintiffs and ExxonMobil appealed that decision to the Ninth Circuit. The Ninth Circuit panel vacated the District Court's $4 billion punitive damage award without argument and sent the case back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm*. On January 28, 2004, the District Court reinstated the punitive damage award at $4.5 billion plus interest. ExxonMobil will appeal the decision to the Ninth Circuit.

On January 29, 1997, a settlement agreement was concluded resolving all remaining matters between the corporation and various insurers arising from the Valdez accident. Under terms of this settlement, ExxonMobil received $480 million. Final income statement recognition of this settlement continues to be deferred in view of uncertainty regarding the ultimate cost to the corporation of the Valdez accident.

Management believes that the likelihood of the jury verdict being upheld is remote. While it is reasonably possible that a liability may have been incurred arising from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

On December 19, 2000, a jury in Montgomery County, Alabama, returned a verdict against the corporation in a dispute over royalties in the amount of $87.69 million in compensatory damages and $3.42 billion in punitive damages in the case of *Exxon Corporation v. State of Alabama, et al*. The verdict was upheld by the trial court on May 4, 2001. On December 20, 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and on November 14, 2003, a state district court jury in Montgomery, Alabama returned a verdict against Exxon Mobil Corporation. The verdict included $63.5 million in compensatory damages and $11.8 billion in punitive damages. ExxonMobil believes the verdict is not justified by the evidence and that the amount of the award is grossly excessive and unconstitutional. ExxonMobil will appeal the decision. Management believes that the likelihood of the jury verdict being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over royalties, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

On May 22, 2001, a state court jury in New Orleans, Louisiana, returned a verdict against the corporation and three other entities in a case brought by a landowner claiming damage to his property. The property had been leased by the landowner to a company that performed pipe cleaning and storage services for customers, including the corporation. The jury awarded the plaintiff $56 million in compensatory damages (90 percent to be paid by the corporation) and $1 billion in punitive damages (all to be paid by the corporation). The damage related to the presence of naturally occurring radioactive material (NORM) on the site resulting from pipe cleaning operations. The award has been upheld at the trial court. ExxonMobil has appealed the judgment to the Louisiana Fourth Circuit Court of Appeals and believes that the judgment should be set aside or substantially reduced on factual and constitutional grounds. Management believes that the likelihood of the jury verdict being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over property damages, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

Issues pending before the U.S. Tax Court for 1979 have been resolved. While issues for 1980-93 remain pending before the court, the ultimate resolution of these issues is not expected to have a materially adverse effect upon the corporation's operations or financial condition.

Other Contingencies

	Equity Company Obligations	Other Third Party Obligations	Total
		(millions of dollars)	
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 983	$ 983
Other guarantees	1,872	424	2,296
Total	$ 1,872	$ 1,407	$3,279

The corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2003 for $3,279 million, primarily relating to guarantees for notes, loans and performance under contracts. This included $983 million representing guarantees of non-U.S. excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements. Also included in this amount were guarantees by consolidated affiliates of $1,872 million, representing ExxonMobil's share of obligations of certain equity companies.

Additionally, the corporation and its affiliates have numerous long-term sales and purchase commitments in their various business activities, all of which are expected to be fulfilled with no adverse consequences material to the corporation's operations or financial condition. Unconditional purchase obligations as defined by accounting standards are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services.

	Payments Due by Period			
	2004	2005-2008	2009 and Beyond	2003 Total Amount
		(millions of dollars)		
Unconditional purchase obligations (1)	$520	$1,703	$2,563	$ 4,786

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(1) Undiscounted obligations of $4,786 million mainly pertain to pipeline throughput agreements and include $1,887 million of obligations to equity companies. The present value of these commitments, excluding imputed interest of $1,543 million, totaled $3,243 million.

The operations and earnings of the corporation and its affiliates throughout the world have been, and may in the future be, affected from time to time in varying degree by political developments and laws and regulations, such as forced divestiture of assets; restrictions on production, imports and exports; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights and environmental regulations. Both the likelihood of such occurrences and their overall effect upon the corporation vary greatly from country to country and are not predictable.

18. Annuity Benefits and Other Postretirement Benefits

	Annuity Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	(millions of dollars)								
Components of net benefit cost									
Service cost	$ 284	$ 224	$ 200	$ 326	$ 257	$ 232	$ 36	$ 30	$ 27
Interest cost	624	577	579	728	621	598	234	220	205
Expected return on plan assets	(418)	(501)	(623)	(552)	(561)	(629)	(31)	(38)	(43)
Amortization of actuarial loss/(gain) and prior service cost	321	121	(25)	384	190	78	96	57	4
Net pension enhancement and curtailment/settlement expense	204	49	14	37	18	27	—	—	—
Net benefit cost	$1,015	$ 470	$ 145	$ 923	$ 525	$ 306	$ 335	$ 269	$ 193
Weighted-average assumptions used to determine net benefit cost for years ended December 31					*(percent)*				
Discount rate	6.75	7.25	7.50	2.1-6.5	2.6-6.8	3.0-7.0	6.75	7.25	7.50
Long-term rate of return on funded assets	9.00	9.50	9.50	6.0-8.5	6.5-8.8	6.5-10.0	9.00	9.50	9.50
Long-term rate of compensation increase	3.50	3.50	3.50	2.4-4.2	2.8-4.3	3.0-5.0	3.50	3.50	3.50

Costs for defined contribution plans were $253 million, $191 million and $132 million in 2003, 2002 and 2001, respectively.

The benefit obligations and plan assets associated with the corporation's principal benefit plans are measured on December 31.

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2003	2002	2003	2002	2003	2002
	(millions of dollars)					
Change in benefit obligation (1)						
Benefit obligation at January 1	$ 9,139	$8,213	$13,543	$11,206	$3,496	$3,131
Service cost	284	224	326	257	36	30
Interest cost	624	577	728	621	234	220
Actuarial loss/(gain)	1,060	990	295	860	1,192	207
Benefits paid	(829)	(876)	(929)	(747)	(338)	(302)

Foreign exchange rate changes	—	—	2,184	1,244	53	2
Other	2	11	166	102	287	208
Projected benefit obligation at December 31	$10,280	$9,139	$16,313	$13,543	$4,960	$3,496
Accumulated benefit obligation at December 31	$ 8,764	$7,984	$14,904	$12,352	—	—
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	6.00	6.75	2.3-6.9	2.1-6.5	6.00	6.75
Long-term rate of compensation increase	3.50	3.50	1.6-4.2	2.4-4.2	3.50	3.50

(1) *The term benefit obligation means “projected benefit obligation” as defined by Statement of Financial Accounting Standards No. 87 (FAS 87), “Employers’ Accounting for Pensions,” for annuity benefits and “accumulated postretirement benefit obligation” as defined by FAS 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions,” for other postretirement benefits.*

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 13 percent for 2004 that declines to 2.5 percent by 2011. The 2003 actuarial loss for other postretirement benefits reflects a change in the health care cost trend rate assumption at year-end 2003. A one-percentage point increase in the health care cost trend rate would increase service and interest cost by $32 million and the postretirement benefit obligation by $358 million. A one-percentage point decrease in the health care cost trend rate would decrease service and interest cost by $26 million and the postretirement benefit obligation by $300 million.

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The company offers a Medicare supplement plan to Medicare-eligible retirees which provides prescription drug benefits. Retirees are required to contribute a portion of the cost to participate in the plan. On December 8, 2003, the President of the United States signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the “Act”). The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to employers sponsoring retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In accordance with Financial Accounting Standards Board Staff Position No. 106-1, the company elected to defer recognition of the effects of the Act on the year-end 2003 accumulated postretirement benefit obligation. Specific authoritative guidance on the accounting for the subsidy is pending and that guidance, when issued, could require a change in previously reported postretirement benefit information.

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2003	2002	2003	2002	2003	2002
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	$4,616	$5,415	$6,735	$6,755	$ 345	$ 395
Actual return on plan assets	1,327	(570)	1,114	(827)	86	(31)
Foreign exchange rate changes	—	—	1,202	647	—	—
Payments directly to participants	133	163	297	259	213	203
Company contribution	2,054	460	779	509	34	33
Benefits paid	(829)	(876)	(929)	(747)	(338)	(302)
Other	—	24	(13)	139	72	47
Fair value at December 31	$7,301	$4,616	$9,185	$6,735	$ 412	$ 345

The data on the preceding page conforms with current accounting standards that specify use of a discount rate at which postretirement liabilities could be effectively settled. The discount rate for calculating year-end postretirement liabilities is based on the year-end rate of interest on a portfolio of high quality bonds. The return on the annuity fund’s actual portfolio of assets has historically been higher than bonds as the majority of pension assets are invested in equities, as illustrated in the table below, which shows the asset allocation of the U.S. annuity fund. The U.S. long-term expected rate of return of 9.0 percent used in 2003 compares to an actual rate of return for the U.S. annuity fund over the past decade of 11 percent. The U.S. long-term expected rate of return will be 9.0 percent in 2004. The company establishes the long-term expected rate of return by developing a forward-looking long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation and the long-term return assumption for each asset class.

	Annuity Assets at December 31		Other Postretirement Assets at December 31	
	2003	2002	2003	2002
	(percent)			
U.S. Funded Benefit Plan Asset Allocation				
Equity securities	71%	74%	76%	63%
Debt securities	25	26	24	37
Other [(1)]	4	—	—	—
Total	100%	100%	100%	100%

(1) *Primarily pending equity and debt security sales transactions.*

The company’s investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes, and broad diversification to reduce the risk of the portfolio. The company primarily invests in funds that follow an index-based strategy to achieve its objectives of diversifying risk while minimizing costs. The funds hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. Asset-liability studies, or simulations of the interaction of cash flows associated with both assets and liabilities, are periodically used to establish the preferred target asset allocation. The target asset allocation for equity securities of 75 percent for the U.S. benefit plans reflects the long-term nature of the liability. The balance of the fund is targeted to debt securities.

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The funding levels of all qualified plans are in compliance with standards set by applicable law or regulation. The corporation contributed $2,054 million to qualified plans in the U.S. in 2003 to maintain the funded status of those plans. Contributions to non-U.S. plans totaled $779 million. In 2004, the company expects to make cash contributions of up to $300 million to U.S. plans, depending upon the outcome of legislative proposals before Congress, and about $450 million to non-U.S. plans. Certain smaller U.S. plans and a number of non-U.S. plans are not funded because local tax conventions and regulatory practices do not encourage funding of these plans. All defined benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the corporation or the respective sponsoring affiliate.

A summary comparing the total plan assets to the total projected benefit obligation is shown in the table below.

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2003	2002	2003	2002	2003	2002
			(millions of dollars)			
Assets in excess of/(less than) projected benefit obligation						
Balance at December 31 (1)	$(2,979)	$(4,523)	$(7,128)	$(6,808)	$(4,548)	$(3,151)
Unrecognized net transition liability/(asset)	—	—	48	30	—	—
Unrecognized net actuarial loss/(gain)	2,723	3,064	4,330	4,340	1,485	377
Unrecognized prior service cost	199	231	363	323	645	490
Net amount recognized	$ (57)	$(1,228)	$(2,387)	$(2,115)	$(2,418)	$(2,284)
Amounts recognized in the consolidated balance sheet consist of:						
Prepaid benefit cost (2)	$ 64	$ 60	$ 794	$ 627	$ —	$ —
Accrued benefit cost (3)	(1,512)	(3,400)	(6,498)	(6,227)	(2,418)	(2,284)
Intangible assets	281	322	429	317	—	—
Equity of minority shareholders	—	—	146	211	—	—
Accumulated other nonowner changes in equity, minimum pension liability adjustment	1,110	1,790	2,742	2,957	—	—
Net amount recognized	$ (57)	$(1,228)	$(2,387)	$(2,115)	$(2,418)	$(2,284)

(1) *Fair value of assets less projected benefit obligation shown in the preceding tables.*

(2) *Included in "Other assets, including intangibles, net" on the Consolidated Balance Sheet.*

(3) *Long-term portion in "Annuity Reserves" and short-term portion in "Accounts payable and accrued liabilities" on the Consolidated Balance Sheet.*

A summary of the change in other nonowner changes in equity related to the minimum pension liability adjustment is shown in the table below.

	Annuity Benefits	
	Total (U.S. and Non-U.S.)	
	2003	2002
	(millions of dollars)	
Increase/(decrease) in accumulated other nonowner changes in equity, before-tax	$ 895	$ (3,798)
Deferred income tax (charge)/credit (see note 20)	(381)	1,373

Increase/(decrease) in accumulated other nonowner changes in equity, after-tax (see Consolidated Statement of Shareholders' Equity, page 45)	$ 514	$ (2,425)

A summary of pension plans with an accumulated benefit obligation in excess of plan assets is shown in the table below.

	Annuity Benefits			
	U.S.		Non-U.S.	
	2003	2002	2003	2002
	(millions of dollars)			
For funded pension plans with accumulated benefit obligations in excess of plan assets:				
Projected benefit obligation	$8,999	$7,948	$9,886	$8,719
Accumulated benefit obligation	7,643	6,907	9,172	8,100
Fair value of plan assets	7,141	4,476	6,719	5,158
Accumulated benefit obligation less fair value of plan assets	502	2,431	2,453	2,942
For unfunded plans covered by book reserves:				
Projected benefit obligation	1,168	1,082	4,342	3,446
Accumulated benefit obligation	1,010	970	3,872	3,042

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19. Disclosures about Segments and Related Information

The upstream, downstream and chemicals functions best define the operating segments of the business that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment. The upstream segment is organized and operates to explore for and produce crude oil and natural gas. The downstream segment is organized and operates to manufacture and sell petroleum products and the chemicals segment is organized and operates to manufacture and sell petrochemicals. These segments are broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the corporation because they are the segments (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the corporation's chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance; and (c) for which discrete financial information is available.

Earnings include special items and transfers are at estimated market prices. Consistent with a change in internal organization in 2002, earnings from the electric power business, previously reported in the other segment, are now shown within non-U.S. upstream. Earnings from the divested coal and minerals businesses are shown as discontinued operations and are included within the other segment. Corresponding items of segment information have been revised for all earlier periods shown on page 67. In addition to discontinued operations, the other segment includes corporate and financing activities, merger expenses and extraordinary gains from required asset divestitures. The interest revenue amount relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt related interest expense of $106 million, $207 million and $105 million in 2003, 2002 and 2001, respectively. Non-U.S. upstream after-tax earnings in 2003 include $1,700 million from a gain on the transfer of shares in Ruhrgas AG, a German gas transmission company. All Other after-tax earnings in 2003 include $2,230 million relating to the positive settlement of a long-running U.S. tax dispute. All Other after-tax earnings in 2003 also include a $550 million positive impact for the required adoption of FAS 143 relating to accounting for asset retirement obligations. Non-U.S. upstream after-tax earnings in 2002 include a special charge of $215 million reflecting the impact on deferred taxes from the 10 percent supplementary tax enacted in the United Kingdom in 2002.

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	Upstream		Downstream		Chemicals			
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	All Other	Corporate Total
	(millions of dollars)							
As of December 31, 2003								
Earnings after income tax	$ 3,905	$10,597	$ 1,348	$ 2,168	$ 381	$ 1,051	$ 2,060	$ 21,510
Earnings of equity companies included above	525	3,335	36	240	16	409	(188)	4,373
Sales and other operating revenue	5,942	15,388	56,373	139,138	7,792	12,398	23	237,054
Intersegment revenue	5,479	15,782	5,627	18,752	3,403	3,237	310	—
Depreciation and depletion expense	1,571	4,072	601	1,548	410	368	477	9,047
Interest revenue	—	—	—	—	—	—	229	229
Interest expense	—	—	—	—	—	—	207	207
Income taxes	2,175	7,237	757	795	67	325	(350)	11,006
Additions to property, plant and equipment	1,701	7,529	1,159	1,416	313	186	555	12,859
Investments in equity companies	1,266	5,176	316	909	266	1,612	—	9,545
Total assets	19,196	56,237	14,436	46,060	7,722	11,786	18,841	174,278
As of December 31, 2002								
Earnings after income tax	$ 2,524	$ 7,074	$ 693	$ 607	$ 384	$ 446	$ (268)	$ 11,460
Earnings of equity companies included above	391	1,761	(40)	27	24	175	(272)	2,066
Sales and other operating revenue	3,896	12,588	48,865	119,167	6,891	9,517	25	200,949
Intersegment revenue	5,020	12,144	4,540	15,157	2,666	2,486	269	—
Depreciation and depletion expense	1,597	3,551	583	1,399	414	348	418	8,310
Interest revenue	—	—	—	—	—	—	297	297
Interest expense	—	—	—	—	—	—	398	398
Income taxes	1,321	5,162	359	44	165	189	(741)	6,499
Additions to property, plant and equipment	1,902	6,122	884	1,357	448	181	543	11,437
Investments in equity companies	1,360	2,867	246	795	265	1,399	—	6,932
Total assets	19,385	47,040	13,562	41,530	7,543	10,581	13,003	152,644
As of December 31, 2001								
Earnings after income tax	$ 3,933	$ 6,803	$ 1,924	$ 2,303	$ 298	$ 409	$ (350)	$ 15,320
Earnings of equity companies included above	482	1,797	89	12	19	118	(343)	2,174
Sales and other operating revenue	5,678	12,889	50,988	123,197	6,918	9,025	20	208,715
Intersegment revenue	5,408	12,322	4,115	16,880	2,186	2,284	178	—
Depreciation and depletion expense	1,447	3,221	598	1,476	408	289	409	7,848
Interest revenue	—	—	—	—	—	—	380	380
Interest expense	—	—	—	—	—	—	293	293
Income taxes	2,089	5,546	1,075	744	82	149	(718)	8,967
Additions to property, plant and equipment	1,985	4,520	827	1,239	390	243	785	9,989

Investments in equity companies	1,371	2,061	329	831	333	1,291	—	6,216
Total assets	18,896	40,901	12,850	37,617	7,495	9,524	15,891	143,174

Geographic Sales and other operating revenue	**2003**	**2002**	**2001**
	(millions of dollars)		
United States	$ 70,128	$ 59,675	$ 63,603
Non-U.S.	166,926	141,274	145,112
Total	$237,054	$200,949	$208,715
Significant non-U.S. revenue sources include:			
Japan	$ 22,360	$ 19,300	$ 21,788
United Kingdom	19,946	17,701	18,628
Canada	17,897	14,087	14,912
Germany	15,764	14,101	13,489
Italy	13,074	10,727	10,431

Long-lived assets	**2003**	**2002**	**2001**
	(millions of dollars)		
United States	$ 34,585	$34,138	$33,637
Non-U.S.	70,380	60,802	55,965
Total	$104,965	$94,940	$89,602
Significant non-U.S. long-lived assets include:			
Canada	$ 10,849	$ 8,469	$ 7,862
United Kingdom	9,615	9,030	8,390
Norway	7,047	6,449	4,627
Japan	4,931	4,637	4,458
Nigeria	3,833	2,633	2,156
Australia	3,440	2,690	2,380
Singapore	3,252	3,407	3,553

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

20. Income, Excise and Other Taxes

	2003			2002			2001		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Income taxes									
Federal or non-U.S.									
Current	$ 1,522	$ 7,426	$ 8,948	$ 351	$ 5,618	$ 5,969	$ 1,729	$ 6,084	$ 7,813
Deferred – net	996	645	1,641	635	(288)	347	712	122	834
U.S. tax on non-U.S. operations	71	—	71	62	—	62	91	—	91
	2,589	8,071	10,660	1,048	5,330	6,378	2,532	6,206	8,738
State	346	—	346	121	—	121	229	—	229
Total income taxes	2,935	8,071	11,006	1,169	5,330	6,499	2,761	6,206	8,967
Excise taxes	6,323	17,532	23,855	7,174	14,866	22,040	7,030	14,877	21,907
All other taxes and duties									
Other taxes and duties	22	37,623	37,645	35	33,537	33,572	45	33,332	33,377
Included in production and manufacturing expenses	976	812	1,788	914	674	1,588	952	751	1,703
Included in SG&A expenses	211	463	674	171	415	586	180	393	573
Total other taxes and duties	1,209	38,898	40,107	1,120	34,626	35,746	1,177	34,476	35,653
Total	$10,467	$64,501	$74,968	$ 9,463	$54,822	$64,285	$10,968	$55,559	$66,527

All other taxes and duties include taxes reported in production and manufacturing, and selling, general and administrative (SG&A) expenses. The above provisions for deferred income taxes include net (charges)/credits for the effect of changes in tax laws and rates of $124 million in 2003, $(194) million in 2002 and $31 million in 2001. Income taxes (charged)/credited directly to shareholders' equity were:

	2003	2002	2001
		(millions of dollars)	
Cumulative foreign exchange translation adjustment	$(233)	$ (331)	$102
Minimum pension liability adjustment	(381)	1,373	139
Unrealized gains and losses on stock investments	(331)	(8)	40
Other components of shareholders' equity	107	86	83

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2003, 2002 and 2001, is as follows:

	2003	2002	2001
		(millions of dollars)	
Earnings before Federal and non-U.S. income taxes			
United States	$ 9,438	$ 4,340	$ 8,315
Non-U.S.	22,182	13,049	15,426
Total	$31,620	$17,389	$23,741
Theoretical tax	$11,067	$ 6,086	$ 8,309
Effect of equity method accounting	(1,531)	(723)	(761)
Non-U.S. taxes in excess of theoretical U.S. tax	1,635	1,355	1,361
U.S. tax on non-U.S. operations	71	62	91
U.S. tax settlement	(541)	—	—
Other U.S.	(41)	(402)	(262)
Federal and non-U.S. income tax expense	$10,660	$ 6,378	$ 8,738
Total effective tax rate	36.4%	39.8%	39.3%

The effective income tax rate includes state income taxes and the corporation's share of income taxes of equity companies. Equity company taxes totaled $983 million in 2003, $778 million in 2002 and $748 million in 2001, primarily all outside the U.S.

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

Deferred tax liabilities/(assets) are comprised of the following at December 31:

Tax effects of temporary differences for:	2003	2002
	(millions of dollars)	
Depreciation	$16,284	$14,254
Intangible development costs	3,821	3,664
Capitalized interest	2,109	2,040
Other liabilities	4,521	3,188
Total deferred tax liabilities	$26,735	$23,146
Pension and other postretirement benefits	$ (2,365)	$ (3,225)
Tax loss carryforwards	(2,500)	(2,350)
Other assets	(3,453)	(3,047)
Total deferred tax assets	$ (8,318)	$ (8,622)
Asset valuation allowances	854	582
Net deferred tax liabilities	$19,271	$15,106

Deferred income tax (assets) and liabilities are included in the balance sheet as shown below. Deferred income tax (assets) and liabilities are classified as current or long-term consistent with the classification of the related temporary difference — separately by tax jurisdiction.

Balance sheet classification	2003	2002
	(millions of dollars)	
Prepaid taxes and expenses	$ (919)	$ (689)
Other assets, including intangibles, net	(1,647)	(2,006)
Accounts payable and accrued liabilities	1,719	1,317
Deferred income tax liabilities	20,118	16,484
Net deferred tax liabilities	$19,271	$15,106

The corporation had $22 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. Unrecognized deferred taxes on remittance of these funds are not expected to be material.

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QUARTERLY INFORMATION

	2003					2002				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(thousands of barrels daily)									
Volumes										
Production of crude oil and natural gas liquids	2,504	2,477	2,485	2,595	2,516	2,541	2,495	2,453	2,497	2,496
Refinery throughput	5,390	5,491	5,555	5,603	5,510	5,416	5,343	5,478	5,536	5,443
Petroleum product sales	7,859	7,795	7,931	8,237	7,957	7,675	7,569	7,763	8,017	7,757
	(millions of cubic feet daily)									
Natural gas production available for sale	12,046	9,283	8,323	10,858	10,119	11,740	9,192	9,222	11,667	10,452
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production (1)	4,512	4,024	3,872	4,405	4,203	4,498	4,027	3,990	4,442	4,238
	(thousands of metric tons)									
Chemical prime product sales	6,880	6,335	6,660	6,692	26,567	6,634	6,702	6,656	6,614	26,606
	(millions of dollars)									
Summarized financial data										
Sales and other operating revenue	$60,188	56,167	58,760	61,939	237,054	$42,592	49,972	53,194	55,191	200,949
Gross profit (2)	$24,588	24,451	24,007	26,043	99,089	$18,804	21,138	20,996	22,920	83,858
Income from continuing operations	$ 6,490	4,170	3,650	6,650	20,960	$ 2,063	2,629	2,629	3,690	11,011
Discontinued operations, net of income tax	$ —	—	—	—	—	$ 27	11	11	400	449
Accounting change, net of income tax	$ 550	—	—	—	550	$ —	—	—	—	—
Net income	$ 7,040	4,170	3,650	6,650	21,510	$ 2,090	2,640	2,640	4,090	11,460
	(dollars per share)									
Per share data										
Income from continuing operations	$ 0.97	0.63	0.55	1.01	3.16	$ 0.30	0.39	0.39	0.54	1.62
Discontinued operations, net of income tax	$ —	—	—	—	—	$ —	0.01	—	0.06	0.07
Accounting change, net of income tax	$ 0.08	—	—	—	0.08	$ —	—	—	—	—
Net income per common share	$ 1.05	0.63	0.55	1.01	3.24	$ 0.30	0.40	0.39	0.60	1.69
Net income per common share – assuming dilution	$ 1.05	0.62	0.55	1.01	3.23	$ 0.30	0.39	0.39	0.60	1.68
Dividends per common share	$ 0.23	0.25	0.25	0.25	0.98	$ 0.23	0.23	0.23	0.23	0.92
Common stock prices										
High	$ 36.60	38.45	38.50	41.13	41.13	$ 44.29	44.58	41.10	36.50	44.58

Low	$ 31.58	34.20	34.90	35.05	31.58	$ 37.60	38.50	29.75	32.03	29.75

(1) *Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.*

(2) *Gross profit equals sales and other operating revenue less estimated costs associated with products sold.*

The price range of ExxonMobil common stock is as reported on the composite tape of the several U.S. exchanges where ExxonMobil common stock is traded. The principal market where ExxonMobil common stock (XOM) is traded is the New York Stock Exchange, although the stock is traded on other exchanges in and outside the United States.

There were 659,444 registered shareholders of ExxonMobil common stock at December 31, 2003. At January 31, 2004, the registered shareholders of ExxonMobil common stock numbered 658,249.

On January 28, 2004, the corporation declared a $0.25 dividend per common share, payable March 10, 2004.

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SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Average sales prices have been calculated by using sales quantities from the corporation's own production as the divisor. Average production costs have been computed by using net production quantities for the divisor. The volumes of crude oil and natural gas liquids (NGL) production used for this computation are shown in the reserves table on page 72 of this report. The net production volumes of natural gas available for sale used in this calculation are shown on page 75 of this report. The volumes of natural gas were converted to oil-equivalent barrels based on a conversion factor of six thousand cubic feet per barrel.

	Consolidated Subsidiaries								
Results of Operations	**United States**	**Canada**	**Europe**	**Asia-Pacific**	**Africa**	**Other**	**Total**	**Non - Consolidated Interests**	**Total Worldwide**
					(millions of dollars)				
2003 – Revenue									
Sales to third parties	$4,257	$2,221	$5,267	$ 2,287	$ 56	$ 459	$14,547	$ 4,365	$ 18,912
Transfers	4,619	2,090	4,397	2,066	4,443	306	17,921	1,808	19,729
	$8,876	$4,311	$9,664	$ 4,353	$4,499	$ 765	$32,468	$ 6,173	$ 38,641
Production costs excluding taxes	1,435	1,054	1,688	558	564	194	5,493	725	6,218
Exploration expenses	257	92	144	146	217	152	1,008	25	1,033
Depreciation and depletion	1,456	782	1,833	727	459	138	5,395	368	5,763
Taxes other than income	540	39	658	447	528	4	2,216	1,697	3,913
Related income tax	2,017	738	2,902	1,046	1,496	94	8,293	1,219	9,512
Results of producing activities	$3,171	$1,606	$2,439	$ 1,429	$1,235	$ 183	$10,063	$ 2,139	$ 12,202
Other earnings [(1)]	209	(78)	1,889	(13)	4	(74)	1,937	363	2,300
Total earnings	$3,380	$1,528	$4,328	$ 1,416	$1,239	$ 109	$12,000	$ 2,502	$ 14,502
2002 – Revenue									
Sales to third parties	$2,499	$1,441	$4,856	$ 1,994	$ 18	$ 343	$11,151	$ 3,426	$ 14,577
Transfers	4,176	1,617	3,334	2,022	3,046	273	14,468	1,296	15,764
	$6,675	$3,058	$8,190	$ 4,016	$3,064	$ 616	$25,619	$ 4,722	$ 30,341
Production costs excluding taxes	1,405	766	1,493	592	455	192	4,903	561	5,464
Exploration expenses	222	66	109	88	177	257	919	38	957
Depreciation and depletion	1,512	681	1,737	651	354	150	5,085	349	5,434
Taxes other than income	459	31	360	403	345	4	1,602	1,179	2,781
Related income tax	1,153	486	2,399	939	972	(122)	5,827	918	6,745
Results of producing activities	$1,924	$1,028	$2,092	$ 1,343	$ 761	$ 135	$ 7,283	$ 1,677	$ 8,960
Other earnings [(1)]	207	(31)	151	(47)	81	(69)	292	346	638
Total earnings	$2,131	$ 997	$2,243	$ 1,296	$ 842	$ 66	$ 7,575	$ 2,023	$ 9,598
2001 – Revenue									
Sales to third parties	$4,045	$1,784	$5,017	$ 1,269	$ 17	$ 342	$12,474	$ 3,326	$ 15,800
Transfers	4,547	1,203	3,927	1,917	2,894	250	14,738	1,306	16,044
	$8,592	$2,987	$8,944	$ 3,186	$2,911	$ 592	$27,212	$ 4,632	$ 31,844

Production costs excluding taxes	1,389	633	1,425	549	414	210	4,620	580	5,200
Exploration expenses	215	109	117	103	217	412	1,173	18	1,191
Depreciation and depletion	1,392	570	1,644	557	318	148	4,629	354	4,983
Taxes other than income	545	54	484	410	375	5	1,873	1,160	3,033
Related income tax	1,957	543	2,567	622	1,023	(98)	6,614	1,037	7,651
Results of producing activities	$3,094	$1,078	$2,707	$ 945	$ 564	$ (85)	$ 8,303	$ 1,483	$ 9,786
Other earnings (1)	355	(37)	132	(42)	33	(66)	375	575	950
Total earnings	$3,449	$1,041	$2,839	$ 903	$ 597	$ (151)	$ 8,678	$ 2,058	$ 10,736

Average sales prices and production costs per unit of production

During 2003									
Average sales prices									
Crude oil and NGL, per barrel	$25.74	$23.84	$27.15	$ 29.03	$28.29	$24.18	$ 26.66	$ 26.51	$ 26.64
Natural gas, per thousand cubic feet	5.06	4.61	3.76	2.84	—	1.04	3.98	4.18	4.02
Average production costs, per barrel (2)	4.48	6.17	4.34	2.84	3.49	5.18	4.31	3.03	4.11
During 2002									
Average sales prices									
Crude oil and NGL, per barrel	$20.80	$20.73	$22.95	$ 24.26	$24.19	$19.43	$ 22.30	$ 21.88	$ 22.25
Natural gas, per thousand cubic feet	2.67	2.34	3.08	2.26	—	0.48	2.65	3.23	2.77
Average production costs, per barrel (2)	3.97	4.53	3.82	2.72	3.57	5.03	3.78	2.44	3.58
During 2001									
Average sales prices									
Crude oil and NGL, per barrel	$19.92	$15.95	$22.79	$ 24.36	$23.34	$20.21	$ 21.30	$ 19.64	$ 21.10
Natural gas, per thousand cubic feet	4.36	3.71	3.28	1.80	—	1.44	3.37	3.48	3.39
Average production costs, per barrel (2)	3.68	3.88	3.40	2.98	3.32	5.85	3.54	2.53	3.39

(1) *Includes earnings from transportation operations, tar sands operations, LNG operations, coal and power operations, technical services agreements, other non-operating activities and adjustments for minority interests.*

(2) *Production costs exclude depreciation and depletion and all taxes. Natural gas included by conversion to crude oil equivalent.*

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Oil and Gas Exploration and Production Costs (unaudited)

The amounts shown for net capitalized costs of consolidated subsidiaries are $3,961 million less at year-end 2003 and $5,969 million less at year-end 2002 than the amounts reported as investments in property, plant and equipment for the upstream in note 10. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to the tar sands and LNG operations, all as required in Statement of Financial Accounting Standards No. 19. Part of the increase in net capitalized costs at year-end 2003 reflects the adoption of FAS 143 (note 2 on page 49).

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total worldwide costs incurred in 2003 were $10,647 million, up $1,492 million from 2002, due primarily to higher development costs. 2002 costs were $9,155 million, up $1,352 million from 2001, due primarily to higher development costs.

	Consolidated Subsidiaries								
Capitalized costs	**United States**	**Canada**	**Europe**	**Asia-Pacific**	**Africa**	**Other**	**Total**	**Non - Consolidated Interests**	**Total Worldwide**
	(millions of dollars)								
As of December 31, 2003									
Property (acreage) costs – Proved	$ 4,188	$ 3,174	$ 219	$ 918	$ 116	$1,018	$ 9,633	$ 59	$ 9,692
– Unproved	663	251	46	1,025	545	475	3,005	1	3,006
Total property costs	$ 4,851	$ 3,425	$ 265	$ 1,943	$ 661	$1,493	$ 12,638	$ 60	$ 12,698
Producing assets	35,737	9,925	39,371	14,478	6,158	2,057	107,726	8,237	115,963
Support facilities	614	113	476	1,083	290	71	2,647	378	3,025
Incomplete construction	1,201	381	1,174	1,133	4,477	1,073	9,439	1,214	10,653
Total capitalized costs	$42,403	$13,844	$41,286	$ 18,637	$11,586	$4,694	$132,450	$ 9,889	$ 142,339
Accumulated depreciation and depletion	26,903	7,401	26,719	11,749	2,980	1,932	77,684	4,780	82,464
Net capitalized costs	$15,500	$ 6,443	$14,567	$ 6,888	$ 8,606	$2,762	$ 54,766	$ 5,109	$ 59,875
As of December 31, 2002									
Property (acreage) costs – Proved	$ 4,433	$ 2,604	$ 202	$ 745	$ 106	$1,018	$ 9,108	$ 56	$ 9,164
– Unproved	657	205	35	900	610	568	2,975	1	2,976
Total property costs	$ 5,090	$ 2,809	$ 237	$ 1,645	$ 716	$1,586	$ 12,083	$ 57	$ 12,140
Producing assets	34,850	7,404	33,385	12,789	4,701	1,983	95,112	7,251	102,363
Support facilities	533	93	489	953	212	85	2,365	335	2,700
Incomplete construction	910	310	2,210	940	2,818	514	7,702	720	8,422
Total capitalized costs	$41,383	$10,616	$36,321	$ 16,327	$ 8,447	$4,168	$117,262	$ 8,363	$ 125,625
Accumulated depreciation and depletion	26,729	5,497	24,111	10,625	2,692	1,881	71,535	4,326	75,861
Net capitalized costs	$14,654	$ 5,119	$12,210	$ 5,702	$ 5,755	$2,287	$ 45,727	$ 4,037	$ 49,764

Costs incurred in property acquisitions, exploration and development activities									
During 2003									
Property acquisition costs – Proved	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
– Unproved	17	7	4	—	17	—	45	—	45
Exploration costs	252	102	153	138	264	243	1,152	29	1,181

Development costs	1,636	644	1,755	929	3,117	558	8,639	782	9,421
Total	$ 1,905	$ 753	$ 1,912	$ 1,067	$ 3,398	$ 801	$ 9,836	$ 811	$ 10,647
During 2002									
Property acquisition costs – Proved	$ 18	$ 8	$ —	$ —	$ —	$ —	$ 26	$ 1	$ 27
– Unproved	13	12	—	—	10	125	160	—	160
Exploration costs	276	109	127	82	301	216	1,111	52	1,163
Development costs	1,676	653	1,785	936	1,708	360	7,118	687	7,805
Total	$ 1,983	$ 782	$ 1,912	$ 1,018	$ 2,019	$ 701	$ 8,415	$ 740	$ 9,155
During 2001									
Property acquisition costs – Proved	$ —	$ —	$ —	$ —	$ 2	$ —	$ 2	$ —	$ 2
– Unproved	95	17	1	(1)	—	10	122	—	122
Exploration costs	352	141	144	148	281	459	1,525	35	1,560
Development costs	1,648	664	1,498	666	995	219	5,690	429	6,119
Total	$ 2,095	$ 822	$ 1,643	$ 813	$ 1,278	$ 688	$ 7,339	$ 464	$ 7,803

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SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2001, 2002 and 2003.

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. In some cases, substantial new investments in additional wells and related facilities will be required to recover these proved reserves. In certain deepwater fields, proved reserves are recorded in a limited number of cases before flow tests are conducted because of the safety and cost implications of conducting the tests. In those situations, other industry accepted analyses are used. Historically, proved reserves recorded using these methods have been immaterial when compared to the corporation's total proved reserves and have also been validated by subsequent flow tests or actual production levels.

Proved reserves include 100 percent of each majority owned affiliate's participation in proved reserves and ExxonMobil's ownership percentage of the proved reserves of equity companies, but exclude royalties and quantities due others. Gas reserves exclude the gaseous equivalent of liquids expected to be removed from the gas on leases, at field facilities and at gas processing plants. These liquids are included in net proved reserves of crude oil and natural gas liquids.

Reserves reported under production sharing and other non-concessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The percentage of conventional liquids and natural gas proved reserves at year-end 2003 that were associated with production sharing contract arrangements was 19 percent of liquids, 12 percent of natural gas and 16 percent on an oil-equivalent basis (gas converted to oil-equivalent at 6 billion cubic feet = 1 million barrels).

	Consolidated Subsidiaries								
Crude Oil and Natural Gas Liquids	**United States**	**Canada**	**Europe**	**Asia-Pacific**	**Africa**	**Other (1)**	**Total**	**Non - Consolidated Interests**	**Total Worldwide**
	(millions of barrels)								
Net proved developed and undeveloped reserves									
January 1, 2001	2,986	1,330	1,558	690	2,384	702	9,650	1,911	11,561
Revisions	89	(9)	68	(1)	94	15	256	8	264
Purchases	—	—	—	—	—	—	—	—	—
Sales	(6)	—	—	—	—	—	(6)	(3)	(9)
Improved recovery	57	5	5	—	34	—	101	20	121
Extensions and discoveries	112	53	79	23	74	—	341	112	453
Production	(210)	(102)	(234)	(90)	(125)	(29)	(790)	(109)	(899)
December 31, 2001	3,028	1,277	1,476	622	2,461	688	9,552	1,939	11,491
Revisions	31	74	59	40	73	26	303	52	355
Purchases	—	—	—	—	—	—	—	—	—
Sales	(13)	—	—	—	—	—	(13)	—	(13)
Improved recovery	3	—	—	—	75	—	78	16	94
Extensions and discoveries	60	40	11	124	145	100	480	297	777
Production	(200)	(106)	(213)	(95)	(128)	(33)	(775)	(106)	(881)
December 31, 2002	2,909	1,285	1,333	691	2,626	781	9,625	2,198	11,823
Revisions	31	14	50	67	176	3	341	34	375
Purchases	1	—	—	—	—	—	1	—	1
Sales	(14)	—	(2)	—	—	—	(16)	—	(16)
Improved recovery	16	3	1	—	66	—	86	25	111

Extensions and discoveries	27	6	10	12	36	491	582	92	674
Production	(178)	(114)	(208)	(86)	(162)	(31)	(779)	(114)	(893)
December 31, 2003	2,792	1,194	1,184	684	2,742	1,244	9,840	2,235	12,075
Developed reserves, included above									
At December 31, 2001	2,567	593	881	477	1,022	232	5,772	1,440	7,212
At December 31, 2002	2,461	685	797	487	1,057	208	5,695	1,505	7,200
At December 31, 2003	2,348	750	805	473	1,107	181	5,664	1,508	7,172

(1) *Middle East, the Caspian region and South America*

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(unaudited)

Net proved developed reserves are those volumes which are expected to be recovered through existing wells with existing equipment and operating methods. Undeveloped reserves are those volumes which are expected to be recovered as a result of future investments to drill new wells, to recomplete existing wells and/or to install facilities to collect and deliver the production from existing and future wells.

Crude oil and natural gas liquids and natural gas production quantities shown are the net volumes withdrawn from ExxonMobil's oil and gas reserves. The natural gas quantities differ from the quantities of gas delivered for sale by the producing function as reported on page 75 due to volumes consumed or flared and inventory changes. Such quantities amounted to approximately 406 billion cubic feet in 2001, 420 billion cubic feet in 2002 and 351 billion cubic feet in 2003.

	Consolidated Subsidiaries								
Natural Gas	**United States**	**Canada**	**Europe**	**Asia-Pacific**	**Africa**	**Other** [(1)]	**Total**	**Non - Consolidated Interests**	**Total Worldwide**
	(billions of cubic feet)								
Net proved developed and undeveloped reserves									
January 1, 2001	13,045	3,516	11,170	8,546	375	667	37,319	18,547	55,866
Revisions	612	(51)	564	(198)	8	(5)	930	(94)	836
Purchases	—	1	—	—	—	—	1	—	1
Sales	(57)	—	(2)	(8)	—	—	(67)	(2)	(69)
Improved recovery	4	15	11	—	2	—	32	7	39
Extensions and discoveries	242	120	360	590	8	120	1,440	1,991	3,431
Production	(1,114)	(418)	(1,172)	(629)	(14)	(54)	(3,401)	(757)	(4,158)
December 31, 2001	12,732	3,183	10,931	8,301	379	728	36,254	19,692	55,946
Revisions	206	30	600	258	17	42	1,153	294	1,447
Purchases	—	2	—	—	—	—	2	—	2
Sales	(43)	—	—	—	—	—	(43)	—	(43)
Improved recovery	1	3	—	—	—	—	4	—	4
Extensions and discoveries	209	83	115	212	52	9	680	1,917	2,597
Production	(1,043)	(419)	(1,138)	(813)	(12)	(44)	(3,469)	(766)	(4,235)
December 31, 2002	12,062	2,882	10,508	7,958	436	735	34,581	21,137	55,718
Revisions	124	(199)	411	23	157	(2)	514	948	1,462
Purchases	10	—	—	—	—	—	10	—	10
Sales	(90)	—	(3)	—	—	—	(93)	(27)	(120)
Improved recovery	9	1	—	—	—	—	10	15	25
Extensions and discoveries	156	45	333	22	1	239	796	923	1,719
Production	(999)	(388)	(1,103)	(718)	(11)	(49)	(3,268)	(777)	(4,045)
December 31, 2003	11,272	2,341	10,146	7,285	583	923	32,550	22,219	54,769
Developed reserves, included above									
At December 31, 2001	10,366	2,517	7,824	6,005	122	404	27,238	8,784	36,022
At December 31, 2002	9,991	2,294	7,326	5,887	112	402	26,012	8,731	34,743
At December 31, 2003	9,513	1,962	7,196	5,764	155	352	24,942	11,292	36,234

(1) *Middle East, the Caspian region and South America*

INFORMATION ON CANADIAN TAR SANDS PROVEN RESERVES NOT INCLUDED ABOVE

In addition to conventional liquids and natural gas proved reserves, ExxonMobil has significant interests in proven tar sands reserves in Canada associated with the Syncrude project. For internal management purposes, ExxonMobil views these reserves and their development as an integral part of total upstream operations. However, for financial reporting purposes, these reserves are required to be reported separately from the oil and gas reserves.

The tar sands reserves are not considered in the standardized measure of discounted future cash flows for conventional oil and gas reserves, which is found on page 74.

Tar Sands Reserves	**Canada**
	(millions of barrels)
At December 31, 2001	821
At December 31, 2002	800
At December 31, 2003	781

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SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Standardized Measure of Discounted Future Cash Flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and rehabilitation obligations. The corporation believes the standardized measure does not provide a reliable estimate of the corporation’s expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including year-end prices, which represent a single point in time and therefore may cause significant variability in cash flows from year to year as prices change.

	Consolidated Subsidiaries								
	United States	Canada	Europe	Asia-Pacific	Africa	Other	Total	Non-Consolidated Interests	Total Worldwide
	(millions of dollars)								
As of December 31, 2001									
Future cash inflows from sales of oil and gas	$ 68,713	$19,573	$58,394	$ 24,452	$42,806	$10,370	$224,308	$ 87,828	$ 312,136
Future production costs	20,008	6,711	15,807	7,801	10,341	3,217	63,885	31,839	95,724
Future development costs	4,613	2,695	5,252	3,262	7,839	831	24,492	3,043	27,535
Future income tax expenses	16,620	3,908	17,416	4,325	13,485	2,091	57,845	22,046	79,891
Future net cash flows	$ 27,472	$ 6,259	$19,919	$ 9,064	$11,141	$ 4,231	$ 78,086	$ 30,900	$ 108,986
Effect of discounting net cash flows at 10%	15,065	2,377	7,338	3,552	6,087	2,553	36,972	18,766	55,738
Discounted future net cash flows	$ 12,407	$ 3,882	$12,581	$ 5,512	$ 5,054	$ 1,678	$ 41,114	$ 12,134	$ 53,248
As of December 31, 2002									
Future cash inflows from sales of oil and gas	$118,905	$38,528	$68,111	$ 36,917	$76,407	$18,321	$357,189	$ 127,089	$ 484,278
Future production costs	26,601	7,910	14,781	9,889	13,673	3,438	76,292	41,463	117,755

Future development costs	5,545	3,157	5,983	3,433	10,454	1,789	30,361	5,583	35,944
Future income tax expenses	34,289	10,261	23,580	8,254	28,190	3,921	108,495	27,633	136,128
Future net cash flows	$ 52,470	$17,200	$23,767	$ 15,341	$24,090	$ 9,173	$142,041	$ 52,410	$ 194,451
Effect of discounting net cash flows at 10%	28,930	6,792	7,788	5,857	11,658	5,634	66,659	31,233	97,892
Discounted future net cash flows	$ 23,540	$10,408	$15,979	$ 9,484	$12,432	$ 3,539	$ 75,382	$ 21,177	$ 96,559
As of December 31, 2003									
Future cash inflows from sales of oil and gas	$127,459	$35,637	$71,937	$ 37,006	$76,969	$28,232	$377,240	$ 146,197	$ 523,437
Future production costs	26,777	11,451	16,090	10,860	15,017	4,438	84,633	51,457	136,090
Future development costs	4,537	3,659	6,966	3,740	7,576	3,801	30,279	5,120	35,399
Future income tax expenses	38,690	7,835	25,080	8,819	29,808	5,587	115,819	33,688	149,507
Future net cash flows	$ 57,455	$12,692	$23,801	$ 13,587	$24,568	$14,406	$146,509	$ 55,932	$ 202,441
Effect of discounting net cash flows at 10%	31,107	4,688	7,970	5,290	10,868	9,894	69,817	33,378	103,195
Discounted future net cash flows	$ 26,348	$ 8,004	$15,831	$ 8,297	$13,700	$ 4,512	$ 76,692	$ 22,554	$ 99,246

Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Consolidated Subsidiaries	2003	2002	2001
		(millions of dollars)	
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	$ 4,013	$ 5,481	$ 2,660
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(25,012)	(19,242)	(20,748)
Development costs incurred during the year	8,299	6,994	5,577
Net change in prices, lifting and development costs	4,052	57,506	(79,693)
Revisions of previous reserves estimates	2,247	4,665	2,520
Accretion of discount	10,513	5,837	12,293
Net change in income taxes	(2,802)	(26,973)	32,780

Total change in the standardized measure during the year	$ 1,310	$ 34,268	$(44,611)

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OPERATING SUMMARY

	2003	2002	2001	2000	1999
			(thousands of barrels daily)		
Production of crude oil and natural gas liquids					
Net production					
United States	610	681	712	733	729
Canada	363	349	331	304	315
Europe	579	592	653	704	650
Asia-Pacific	237	260	247	253	307
Africa	442	349	342	323	326
Other Non-U.S.	285	265	257	236	190
Worldwide	2,516	2,496	2,542	2,553	2,517
			(millions of cubic feet daily)		
Natural gas production available for sale					
Net production					
United States	2,246	2,375	2,598	2,856	2,871
Canada	943	1,024	1,006	844	683
Europe	4,498	4,463	4,595	4,463	4,438
Asia-Pacific	1,803	2,019	1,547	1,755	2,027
Other Non-U.S.	629	571	533	425	289
Worldwide	10,119	10,452	10,279	10,343	10,308
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production [(1)]	4,203	4,238	4,255	4,277	4,235
			(thousands of barrels daily)		
Refinery throughput					
United States	1,806	1,834	1,811	1,862	1,930
Canada	450	447	449	451	441
Europe	1,566	1,539	1,563	1,578	1,782
Asia-Pacific	1,390	1,379	1,436	1,462	1,537
Other Non-U.S.	298	244	283	289	287
Worldwide	5,510	5,443	5,542	5,642	5,977
Petroleum product sales					
United States	2,729	2,731	2,751	2,669	2,918
Canada	602	593	585	577	587
Europe	2,061	2,042	2,079	2,129	2,597
Asia-Pacific and other Eastern Hemisphere	2,075	1,889	2,024	2,090	2,223
Latin America	490	502	532	528	562
Worldwide	7,957	7,757	7,971	7,993	8,887
Gasoline, naphthas	3,238	3,176	3,165	3,122	3,428
Heating oils, kerosene, diesel oils	2,432	2,292	2,389	2,373	2,658
Aviation fuels	662	691	721	749	813
Heavy fuels	638	604	668	694	706
Specialty petroleum products	987	994	1,028	1,055	1,282

Worldwide	7,957	7,757	7,971	7,993	8,887
	(thousands of metric tons)				
Chemical prime product sales					
United States	10,740	11,386	11,078	11,736	11,719
Non-U.S.	15,827	15,220	14,702	13,901	13,564
Worldwide	26,567	26,606	25,780	25,637	25,283

Operating statistics include 100 percent of operations of majority owned subsidiaries; for other companies, crude production, gas, petroleum product and chemical prime product sales include ExxonMobil's ownership percentage, and refining throughput includes quantities processed for ExxonMobil. Net production excludes royalties and quantities due others when produced, whether payment is made in kind or cash.

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

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SIGNATURES

Pursuant to the requirements of Section 13 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.

EXXON MOBIL CORPORATION

By: /s/ LEE R. RAYMOND

(Lee R. Raymond,
Chairman of the Board)

Dated March 15, 2004

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Richard E. Gutman, Robert E. Harayda and Brian A. Maher, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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.

/s/ LEE R. RAYMOND (Lee R. Raymond)	Chairman of the Board (Principal Executive Officer)	March 15, 2004
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director	March 15, 2004
/s/ DONALD V. FITES (Donald V. Fites)	Director	March 15, 2004

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/s/ JAMES R. HOUGHTON (James R. Houghton)	Director	March 15, 2004
/s/ WILLIAM R. HOWELL (William R. Howell)	Director	March 15, 2004
/s/ HELENE L. KAPLAN (Helene L. Kaplan)	Director	March 15, 2004
/s/ REATHA CLARK KING (Reatha Clark King)	Director	March 15, 2004
/s/ PHILIP E. LIPPINCOTT (Philip E. Lippincott)	Director	March 15, 2004
/s/ HARRY J. LONGWELL (Harry J. Longwell)	Director	March 15, 2004
/s/ HENRY A. MCKINNELL, JR. (Henry A. McKinnell, Jr.)	Director	March 15, 2004
/s/ MARILYN CARLSON NELSON (Marilyn Carlson Nelson)	Director	March 15, 2004
/s/ WALTER V. SHIPLEY (Walter V. Shipley)	Director	March 15, 2004
/s/ REX W. TILLERSON (Rex W. Tillerson)	Director	March 15, 2004
/s/ DONALD D. HUMPHREYS (Donald D. Humphreys)	Controller (Principal Accounting Officer)	March 15, 2004

/s/ FRANK A. RISCH (Frank A. Risch)	Treasurer (Principal Financial Officer)	March 15, 2004

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INDEX TO EXHIBITS

3(i).	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
3(ii).	By-Laws, as revised to July 31, 2002 (incorporated by reference to Exhibit 3(ii) to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
10(iii)(a.1).	1993 Incentive Program (incorporated by reference to Exhibit 10(iii)(a) to Annual Report on Form 10-K for 2002).*
10(iii)(a.2).	2003 Incentive Program (incorporated by reference to Appendix B to the Proxy Statement of Exxon Mobil Corporation dated April 17, 2003).*
10(iii)(b).	2001 Nonemployee Directors' Deferred Compensation Plan (incorporated by reference to Exhibit 10(iii)(b) to the registrant's Annual Report on Form 10-K for 2000).*
10(iii)(c).	Restricted Stock Plan for Nonemployee Directors, as amended (incorporated by reference to Exhibit 10(iii)(c) to the registrant's Annual Report on Form 10-K for 2001).*
10(iii)(d).	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the registrant's Annual Report on Form 10-K for 1999).*
10(iii)(e).	Short Term Incentive Program, as amended.*
10(iii)(f).	1997 Nonemployee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f) to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2000).*
10(iii)(g).	1995 Mobil Incentive Compensation and Stock Ownership Plan (incorporated by reference to Exhibit 10(iii)(g) to the registrant's Annual Report on Form 10-K for 2000).*
10(iii)(i).	Supplemental Employees Savings Plan of Mobil Oil Corporation (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K of Mobil Corporation filed March 31, 1999).*
10(iii)(j).	Form of terms for restricted stock agreements with executive officers.*
12.	Computation of ratio of earnings to fixed charges.
14.	Code of Ethics and Business Conduct.
21.	Subsidiaries of the registrant.
23.	Consent of PricewaterhouseCoopers LLP, Independent Accountants.

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INDEX TO EXHIBITS—(continued)

31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Financial Officer.
32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.

* Compensatory plan or arrangement required to be identified pursuant to Item 15(a)(3) of this Annual Report on Form 10-K.

The registrant has not filed with this report copies of the instruments defining the rights of holders of long-term debt of the registrant and its subsidiaries for which consolidated or unconsolidated financial statements are required to be filed. The registrant agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon request.