EXXON MOBIL CORP
Form 10-K
February 28, 2007

2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006

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	13-5409005
(State or other jurisdiction of incorporation or organization)	(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 (5,693,398,774 shares outstanding at January 31, 2007)	**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**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes _ü_ No ____

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ___ No _ü_

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 _ü_ No ____

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer _ü_ Accelerated filer ____ Non-accelerated filer ___

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act). Yes ___ No _ü_

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2006, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $61.35 on the New York Stock Exchange composite tape, was in excess of $364 billion.

Documents Incorporated by Reference:

Proxy Statement for the 2007 Annual Meeting of Shareholders (Part III)

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EXXON MOBIL CORPORATION

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2006

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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 most other countries of the world. 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 commodity 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 air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as well as projects to reduce nitrogen oxide and sulfur oxide emissions and expenditures for asset retirement obligations. ExxonMobil s 2006 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil s share of equity company expenditures, were about $3.2 billion, of which $1.1 billion were capital expenditures and $2.1 billion were included in expenses. The total cost for such activities is expected to remain in this range in 2007 and 2008 (with capital expenditures approximately 40 percent of the total).

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the following: Quarterly Information , Note 17: Disclosures about Segments and Related Information and Operating Summary . Information on oil and gas reserves is contained in the Oil and Gas Reserves part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion of the Financial Section of this report. Information on Company-sponsored research and development activities is contained in Note 3: Miscellaneous Financial Information of the Financial Section of this report.

The number of regular employees was 82.1 thousand, 83.7 thousand and 85.9 thousand at years ended 2006, 2005 and 2004, respectively. Regular employees are defined as active executive, management, professional, technical and wage employees who work full time or part time for the Corporation and are covered by the Corporation s benefit plans and programs. Regular employees do not include employees of the company-operated retail sites (CORS). The number of CORS employees was 24.3 thousand, 22.4 thousand and 19.3 thousand at years ended 2006, 2005 and 2004, 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

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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 without charge to shareholders who request them. Information on our website is not incorporated into this report.

Item 1A. ***Risk Factors*****.**

ExxonMobil s financial and operating results are subject to a number of factors, many of which are not within the Company s control. These factors include the following:

Industry and Economic Factors: The oil and gas business is fundamentally a commodity business. This means the operations and earnings of the Corporation and its affiliates throughout the world may be significantly affected by changes in oil, gas and petrochemical prices and by changes in margins on gasoline and other refined products. Oil, gas, petrochemical and product prices and margins in turn depend on local, regional and global events or conditions that affect supply and demand for the relevant commodity. 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 regional energy demand (such as the demand for heating oil or gas in winter) as well as severe weather events (such as hurricanes) that can disrupt supplies or interrupt the operation of ExxonMobil facilities;
- 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.

Under certain market conditions, factors that have a positive impact on one segment of our business may have a negative impact on another segment and vice versa.

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 chemical needs of both industrial and individual consumers. The Corporation competes with other firms in the sale or purchase of needed goods and 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 businesses, is ExxonMobil s ability to manage expenses successfully. This requires continuous management focus on reducing unit costs and improving efficiency including through technology improvements, cost control, productivity enhancements and regular reappraisal of our asset portfolio as described elsewhere in this report.

Political and Legal 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 and legal factors including:

- political instability or lack of well-established and reliable legal systems in areas where the Corporation operates;

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other political developments and laws and regulations, such as expropriation or forced divestiture of assets, unilateral cancellation or modification of contract terms, and de-regulation of certain energy markets;

laws and regulations related to environmental or energy security matters, including those addressing alternative energy sources and the risks of global climate change;

restrictions on exploration, production, imports and exports;

restrictions on the Corporation s ability to do business with certain countries, or to engage in certain areas of business within a country;

price controls;

tax or royalty increases, including retroactive claims;

war or other international conflicts; and

civil unrest.

Both the likelihood of these occurrences and their overall effect upon the Corporation vary greatly from country to country and are not predictable. A key component of the Corporation s strategy for managing political risk is geographic diversification of the Corporation s assets and operations.

Project Factors: In addition to some of the factors cited above, ExxonMobil s results depend upon the Corporation s ability to develop and operate major projects and facilities as planned. The Corporation s results will therefore be affected by events or conditions that impact the advancement, operation, cost or results of such projects or facilities, including:

the outcome of negotiations with co-venturers, governments, suppliers, customers or others (including, for example, our ability to negotiate favorable long-term contracts with customers, or the development of reliable spot markets, that may be necessary to support the development of particular production projects);

reservoir performance and natural field decline;

changes in operating conditions and costs, including costs of third party equipment or services such as drilling rigs and shipping;

security concerns or acts of terrorism that threaten or disrupt the safe operation of company facilities; and the occurrence of unforeseen technical difficulties (including technical problems that may delay start-up or interrupt production from an Upstream project or that may lead to unexpected downtime of refineries or petrochemical plants).

See section 1 of Item 2 of this report for a discussion of additional factors affecting future capacity growth and the timing and ultimate recovery of reserves.

Market Risk Factors: See the Market Risks, Inflation and Other Uncertainties portion 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.

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Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Part of the information in response to this item and to the Securities Exchange Act Industry Guide 2 is contained in Note 8: Property, Plant and Equipment and Asset Retirement Obligations and in the Supplemental Information on Oil and Gas Exploration and Production Activities, both included in the Financial Section of this report.

Information with regard to oil and gas producing activities follows:

1. Net Reserves of Crude Oil and Natural Gas Liquids and Natural Gas at Year-End 2006

Estimated proved reserves are shown in the Oil and Gas Reserves part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion of the Financial Section of this report. No major discovery or other favorable or adverse event has occurred since December 31, 2006, that 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 the Standardized Measure of Discounted Future Cash Flows part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion of the Financial Section of this report.

The table below summarizes the oil-equivalent proved reserves in each geographic area for consolidated subsidiaries as detailed in the Oil and Gas Reserves part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion of the Financial Section of this report for the year ended December 31, 2006. The Corporation has reported 2005 and 2006 proved reserves on the basis of December 31 prices and costs. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

	United States	Canada	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	South America	Total Consolidated
	(millions of barrels)							
Liquids	1,884	962	748	2,089	1,287	791	433	8,194
	(billions of cubic feet)							
Natural gas	12,049	1,517	7,089	986	9,583	789	467	32,480

	(millions of oil-equivalent barrels)							
Oil-equivalent basis	3,892	1,215	1,930	2,253	2,884	922	511	13,607

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Additional detail on developed and undeveloped oil-equivalent proved reserves is shown in the table below.

	Year-End 2006		Year-End 2005	
	Developed	Undeveloped	Developed	Undeveloped
	(millions of oil-equivalent barrels)			
Consolidated Subsidiaries				
United States	3,013	879	3,411	984
Canada	921	294	862	254
Europe	1,448	482	1,711	572
Africa	1,416	837	1,281	1,171
Asia Pacific/Middle East	2,070	814	1,475	253
Russia/Caspian	183	739	93	751
South America	252	259	279	275
Total	9,303	4,304	9,112	4,260
Equity Companies				
United States	329	84	345	91
Europe	1,675	429	1,713	468
Asia Pacific/Middle East	1,948	2,995	1,938	2,629
Russia/Caspian	679	364	713	373
Total	4,631	3,872	4,709	3,561

In the preceding reserves information, and in the reserves tables in the Oil and Gas Reserves part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion of the Financial Section of this report, consolidated subsidiary and equity company reserves are reported separately. However, the Corporation operates its business with the same view of equity company reserves as it has for reserves from consolidated subsidiaries.

The Corporation s overall volume capacity outlook, based on projects coming on stream as anticipated, is for production capacity to grow over the period 2007-2011. However, actual volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, asset sales, weather events, price effects on production sharing contracts and other factors as described in Item 1A Risk Factors 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, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. 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 amount recovered 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 2006, 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 2005, 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,

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Form EIA-23 information does not include gas plant liquids. The difference between the oil reserves and gas reserves reported on EIA-23 and those reported in the registrant s Annual Report on Form 10-K for 2005 exceeds five percent.

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

Reference is made to the Results of Operations part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion 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 in the Oil and Gas Reserves part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion of the Financial Section of this report. The volumes of natural gas used in the calculation are the production volumes of natural gas available for sale and thus are different from those shown in the reserves table in the Oil and Gas Reserves part of the Supplemental Information on Oil and Gas Exploration and Production Activities portion of the Financial Section of this report due to volumes consumed or flared. The volumes of natural gas were converted to oil-equivalent barrels based on a conversion factor of six thousand cubic feet per barrel.

4. Gross and Net Productive Wells

	Year-End 2006				Year-End 2005			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	28,139	10,644	9,059	5,468	28,288	10,865	9,187	5,441
Canada	5,662	4,975	5,857	3,058	5,967	5,214	6,115	2,991
Europe	1,780	528	1,300	509	1,872	590	1,294	512
Africa	823	348	12	5	674	277	14	6
Asia Pacific/Middle East	2,191	587	267	184	1,991	532	259	180
Russia/Caspian	82	17			77	16	2	1
South America	154	64	85	30	154	64	89	30
Total	38,831	17,163	16,580	9,254	39,023	17,558	16,960	9,161

The numbers of wells operated at year-end 2006 were 16,914 gross wells and 13,988 net wells. At year-end 2005, the numbers of operated wells were 17,351 gross wells and 14,028 net wells.

5. Gross and Net Developed Acreage

	Year-End 2006		Year-End 2005	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	9,045	5,178	9,194	5,260
Canada	4,812	2,099	4,869	2,238
Europe	10,678	4,418	11,303	4,687
Africa	1,842	717	1,497	545
Asia Pacific/Middle East	8,210	1,655	7,876	1,570
Russia/Caspian	531	116	531	116
South America	690	232	690	232
Total	35,808	14,415	35,960	14,648

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

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6. Gross and Net Undeveloped Acreage

	Year-End 2006		Year-End 2005	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	9,917	6,062	10,388	6,413
Canada	10,659	4,785	10,816	4,822
Europe	8,089	2,727	8,782	2,778
Africa	39,306	24,075	49,328	29,048
Asia Pacific/Middle East	13,466	7,462	7,114	3,797
Russia/Caspian	2,181	449	2,561	569
South America	20,803	17,229	26,552	19,513
Total	104,421	62,789	115,541	66,940

ExxonMobil s investment in developed and undeveloped acreage is comprised of numerous concessions, blocks and leases. The terms and conditions under which the Corporation maintains exploration and/or production rights to the acreage are property-specific, contractually defined and vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration. In some instances, the Corporation may elect to relinquish acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, the Corporation has generally been successful in obtaining extensions.

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.

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

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.

Netherlands

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

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Production rights granted prior to January 1, 2003, remain subject to their existing terms, and differ slightly for onshore and offshore areas. Onshore production licenses issued prior to 1988 were indefinite; from 1988 they were issued for a period as explicitly defined in the license, ranging from 35 to 45 years. Offshore production licenses issued before 1976 were issued for a fixed period of 40 years; from 1976 they were again issued for a period as explicitly defined in the license, ranging from 15 to 40 years.

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 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, many of the early licenses issued under the first four licensing rounds provided for an initial term of six years with relinquishment of at least one-half of the original area at the end of the initial term, subject to extension for a further 40 years. ExxonMobil s licenses issued in 2005 as part of the 23rd licensing round have an initial term of four years with a second term extension of four years and a final term of 18 years. There is a mandatory relinquishment of 50-percent of the acreage after the initial term and of all acreage that is not covered by a development plan at the end of the second term.

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.

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.

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Equatorial Guinea

Exploration and production activities are governed by production sharing contracts negotiated with the State Ministry of Mines, Industry 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. A new Hydrocarbons Law was enacted in November 2006. Under the new law, the exploration terms for new production sharing contracts are expected to be four to five years with a maximum of two one-year extensions, unless the Ministry agrees otherwise.

Nigeria

Exploration and production activities in the deepwater offshore areas are typically governed by production sharing contracts (PSCs) with the national oil company, the Nigerian National Petroleum Corporation (NNPC). NNPC 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. Operations under these pre-1969 OMLs are conducted under a joint venture agreement with NNPC rather than a PSC.

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 NNPC 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 joint venture 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.

ASIA PACIFIC / MIDDLE EAST

Australia

Exploration and production activities are conducted offshore and are governed by Federal legislation. Exploration permits are granted for an initial term of 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 July 1998, production licenses were granted initially for 21 years, with a further renewal of 21 years and thereafter indefinitely , i.e., for

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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). Effective from July 1998, new production licenses are granted indefinitely .

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-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, depending on water depth, 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 (an additional extension of three years is possible in certain circumstances). 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 within the maximum possible retention time of 15 years. Petroleum Retention licenses are granted for five-year terms, and may be extended, at the Minister s discretion, twice for the maximum retention time of 15 years.

Qatar

The State of Qatar grants gas production development project 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.

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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. The Government of Yemen awarded a five-year extension of the Marib PSA, but later repudiated the extension and expelled the concession holders. The parties are now in arbitration over the validity of the extension.

Thailand

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

United Arab Emirates

Exploration and production activities for the major onshore oilfields 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. An interest in the Upper Zakum field, a major offshore field, was acquired effective as of January 1, 2006, for a term expiring March 9, 2026, on fiscal terms consistent with the Company s existing interests in Abu Dhabi.

RUSSIA/CASPIAN

Azerbaijan

The production sharing agreement (PSA) for the development of the Azeri-Chirag-Gunashli field 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, exploration 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 was six years followed by separate appraisal periods for each discovery. The production period for each discovery, which includes development, is for 20 years from the date of declaration of commerciality with the possibility of two ten-year extensions.

Russia

Terms for ExxonMobil s acreage are fixed by the production sharing agreement (PSA) that became effective in 1996 between the Russian government and the Sakhalin-1 consortium, of which ExxonMobil is the operator. The term of the PSA is 20 years from the Declaration of Commerciality, which would be 2021. The term may be extended thereafter in 10-year increments as specified in the PSA.

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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 Association Agreements containing risk/profit provisions negotiated with the national oil company or its affiliates. Association Agreements are awarded for a term not to exceed 39 years. These agreements have an exploration and a production phase. The term of production begins after the exploration phase and runs for 20 years with the possibility of an extension, so long as the total contract term does not exceed 39 years.

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. The Venezuelan Government has indicated a desire to increase ownership by the National Oil Company (PdVSA) to greater than 50 percent in the projects covered by these agreements and to make other changes to applicable fiscal terms.

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8. Number of Net Productive and Dry Wells Drilled

	2006	2005	2004
A. Net Productive Exploratory Wells Drilled			
United States	10	13	11
Canada	3	1	2
Europe	2	4	3
Africa	4	5	2
Asia Pacific/Middle East	2	1	2
Russia/Caspian			1
South America			
Total	21	24	21
B. Net Dry Exploratory Wells Drilled			
United States	5	5	6
Canada			4
Europe	2	1	1
Africa	4	5	4
Asia Pacific/Middle East		1	
Russia/Caspian		1	
South America	1		
Total	12	13	15
C. Net Productive Development Wells Drilled			
United States	552	537	568
Canada	371	263	466
Europe	22	19	24
Africa	64	61	64
Asia Pacific/Middle East	25	50	35
Russia/Caspian	5	7	4
South America	2	9	3
Total	1,041	946	1,164
D. Net Dry Development Wells Drilled			
United States	5	8	13
Canada	1	2	2
Europe	4	2	2
Africa	1		
Asia Pacific/Middle East		2	1
Russia/Caspian			
South America			
Total	11	14	18
Total number of net wells drilled	1,085	997	1,218

9. Present Activities

A. Wells Drilling

	Year-End 2006		Year-End 2005	
	Gross	Net	Gross	Net
United States	214	109	148	84
Canada	223	182	148	94
Europe	55	11	46	12
Africa	50	19	53	21
Asia Pacific/Middle East	49	14	70	24
Russia/Caspian	33	6	38	8
South America	3	1	3	1
Total	627	342	506	244

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B. Review of Principal Ongoing Activities in Key Areas

During 2006, 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 2006. At year-end 2006, ExxonMobil s acreage totaled 11.2 million net acres, of which 2.6 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During 2006, 543.9 net exploration and development wells were completed in the inland lower 48 states and 3.0 net development wells were completed offshore in the Pacific. Tight gas development continues in the Piceance Basin of Colorado. Participation in Alaska production and development continued and a total of 14.6 net development wells were drilled. On Alaska s North Slope, activity continued on the Western Region Development Project (primarily the Orion field) with development drilling and engineering design for facility expansions.

ExxonMobil s net acreage in the Gulf of Mexico at year-end 2006 was 2.4 million acres. A total of 10.9 net exploration and development wells were completed during the year. Installation and commissioning of the semi-submersible production and drilling vessel continued for the Thunder Horse development in 2006. Startup, delayed due to a listing incident and subsea manifolds that failed during testing, is anticipated to occur in 2008.

CANADA

ExxonMobil s year-end 2006 acreage holdings totaled 6.9 million net acres, of which 3.1 million net acres were offshore. A total of 375.0 net exploration and development wells were completed during the year. In eastern Canada, work continued on the Sable Compression project. Hook-up and commissioning of the compression platform was completed at Sable in the fourth quarter of 2006.

EUROPE

France

ExxonMobil divested its oil and gas exploration and production assets in 2006.

Germany

A total of 2.3 million net onshore acres and 0.1 million net offshore acres were held by ExxonMobil at year-end 2006, with 4.6 net development and exploration wells drilled during the year.

Netherlands

ExxonMobil s net interest in licenses totaled approximately 1.8 million acres at year-end 2006, 1.5 million acres onshore and 0.3 million acres offshore. A total of 3.6 net exploration and development wells were completed during the year. The offshore K17-FA field started up. The multi-year onshore

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project to renovate production clusters, install new compression to maintain capacity and extend field life continued.

Norway

ExxonMobil s net interest in licenses at year-end 2006 totaled approximately 0.8 million acres, all offshore. ExxonMobil participated in 9.3 net exploration and development well completions in 2006. Production was initiated at Ringhorne East in March and Fram East in October. The Ormen Lange, Statfjord Late Life, Skarv, Volve, Tyrihans and Njord Gas Export projects are in progress.

United Kingdom

ExxonMobil s net interest in licenses at year-end 2006 totaled approximately 1.9 million acres, all offshore. A total of 12.1 net exploration and development wells were completed during the year. The Cutter and Merganser projects commenced production during 2006. Other projects progressed in 2006 include Caravel and Starling.

AFRICA

Angola

ExxonMobil s year-end 2006 acreage holdings totaled 0.7 million net offshore acres and 9.2 net exploration and development wells were completed during the year. On Block 15, development drilling continued on Kizomba A and Kizomba B. Development construction continued on the Marimba North project, which will tie-back to the Kizomba A FPSO. Planning for the Kizomba C development concluded and construction is fully underway. A block-wide 4D seismic acquisition program concluded at mid-year. On Block 17, the Dalia project started-up in December. Construction and development activities continued on the Rosa project.

Cameroon

ExxonMobil s acreage totaled 0.3 million net offshore acres at year-end 2006.

Chad

ExxonMobil s net year-end 2006 acreage holdings consisted of 3.3 million onshore acres, with 32.8 net exploration and development wells completed during the year. Production began from the Moundouli field.

Equatorial Guinea

ExxonMobil s acreage totaled 0.3 million net offshore acres at year-end 2006, with 8.3 net development wells completed during the year.

Nigeria

ExxonMobil s net acreage totaled 1.3 million offshore acres at year-end 2006, with 21.5 net exploration and development wells completed during the year. Several major project start-ups were executed in the year. The Yoho field (OML 104) full-field production platform started production in January 2006. The Erha Floating Production, Storage and Offloading (FPSO) vessel commenced production from the deepwater Erha field (OML 133) in March 2006. Production was initiated from the Erha North field (tie-back to the Erha FPSO) in September 2006. The ExxonMobil-operated East

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Area Additional Oil Recovery project started up in January 2006 and pipeline tie-ins continued throughout the year. This project positions Nigerian operations for a significant reduction in flaring in 2007. Detailed design and construction continued on the ExxonMobil-operated East Area Natural Gas Liquids II project. The Amenam-Kpono Phase 2 Gas project started up in late 2006.

ASIA PACIFIC / MIDDLE EAST

Australia

ExxonMobil s net year-end 2006 acreage holdings totaled 1.4 million acres, all offshore. During 2006, a total of 5.8 net exploration and development wells were drilled.

Indonesia

At year-end 2006, ExxonMobil had 3.9 million net acres, 3.0 million acres offshore and 0.9 million acres onshore. Project activities commenced in mid-2006 on the Banyu Urip development in the Cepu Contract Area after the execution of commercial agreements and approval of the Plan of Development by the government of Indonesia.

Japan

ExxonMobil s net offshore acreage was 36 thousand acres at year-end 2006.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.5 million net acres offshore Malaysia at year-end 2006. During the year, a total of 4.0 net exploration and development wells were completed. The Guntong E platform, part of the Guntong Hub development, started up in July 2006. Infill drilling wells were successfully completed at the Jerneh-A platform. Drilling activities are currently ongoing at Tabu-B and Angsi-C.

Papua New Guinea

A total of 0.5 million net onshore acres were held by ExxonMobil at year-end 2006, with 1.0 net development well completed during the year.

Qatar

Production and development activities continued on natural gas projects in Qatar. Liquefied natural gas (LNG) operating companies include:

Qatar Liquefied Gas Company Limited (QG I)

Qatar Liquefied Gas Company Limited (II) (QG II)

Ras Laffan Liquefied Natural Gas Company Limited (RL I)

Ras Laffan Liquefied Natural Gas Company Limited (II) (RL II)

Ras Laffan Liquefied Natural Gas Company Limited (3) (RL 3)

In addition, ExxonMobil s Al Khaleej Gas (AKG) Phase 1 project supplied pipeline gas to domestic industrial customers. The AKG facilities add sales gas capacity of up to 750 mcfd (millions of cubic feet per day) and produced associated condensate and LPG (Liquid Petroleum Gas). The AKG Phase 2 project is planned to add sales gas capacity of up to 1,250 mcfd, while recovering associated condensate and LPG.

At the end of 2006, 60 (gross) wells supplied natural gas to currently-producing LNG and pipeline gas sales facilities and drilling is underway to complete wells that will supply the new QG II, RL 3 and AKG 2 projects. At year-end 2006, ExxonMobil had 1.1 million net acres, 1.0 million acres onshore and 0.1 million acres offshore. During 2006, 9.9 net development wells were completed.

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Qatar LNG capacity volumes at year-end included 9.7 MTA (millions of metric tons per annum) in QG trains 1-3 and a combined 20.7 MTA in RL I trains 1-2 and RL II trains 3-5. In November 2006 production commenced at RL II train 5, although offshore facilities were not completed at year-end 2006. Construction of QG II trains 4-5 will add planned capacity of 15.6 MTA when complete. In addition, construction of RL 3 trains 6-7 will add planned capacity of 15.6 MTA when complete.

The conversion factor to translate Qatar LNG volumes (millions of metric tons MT) into gas volumes (billions of cubic feet BCF) is dependent on the gas quality and the quality of the LNG produced. The conversion factors are approximately 46 BCF/MT for QG I trains 1-3, RL I trains 1-2, RL II train 3, and approximately 49 BCF/MT for QG II trains 4-5, RL II trains 4-5, and RL 3 trains 6-7.

Republic of Yemen

ExxonMobil s net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 2006.

Thailand

ExxonMobil s net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2006.

United Arab Emirates

In 2006, ExxonMobil acquired a 28 percent equity in the offshore Upper Zakum oil concession. The concession ends on March 9, 2026.

ExxonMobil s net acreage in the Abu Dhabi oil concessions was 0.6 million acres at year-end 2006, 0.4 million acres onshore and 0.2 million acres offshore. During the year, a total of 6.4 net development and exploration wells were completed. The Northeast Bab Phase 1 new field development project was completed successfully.

RUSSIA / CASPIAN

Azerbaijan

At year-end 2006, ExxonMobil s net acreage, located in the Caspian Sea offshore of Azerbaijan, totaled 60 thousand acres. At the Azeri-Chirag-Gunashli (ACG) field, 1.0 net development well was completed and production ramp-up continued. The second phase of full field development was initiated with the start-up of West Azeri in January 2006 followed by East Azeri in November 2006 with full-field oil production increased to 660 thousand barrels of oil per day (gross) by year-end. Seventy percent of the construction on the Phase 3 Deep Water Gunashli Project was complete at year-end, with production start up anticipated in 2008.

Kazakhstan

ExxonMobil s net acreage totaled 0.2 million acres onshore and 0.2 million acres offshore at year-end 2006, with 1.4 net exploration and development wells completed during 2006. At Tengiz, construction of the 285 thousand barrels of oil per day (gross) expansion project continued through 2006. Engineering and construction of the initial phase of the Kashagan field continued during 2006.

Russia

ExxonMobil s net acreage holdings at year-end 2006 were 0.1 million acres, all offshore. A total of 3.0 net development wells were completed in the Chayvo field during the year. Production from the

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field began in October 2005 through an early production system for domestic Russian oil and gas sales and continued through the third quarter 2006. Full-field production with crude oil export and domestic gas sales began in the fourth quarter 2006 and drilling activities are continuing. Phase 1 facilities 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, a mainland terminal and an offshore loading buoy for shipment of oil by tanker.

SOUTH AMERICA

Argentina

ExxonMobil s net acreage totaled 0.2 million onshore acres at year-end 2006, and there were 1.9 net development wells completed during the year.

Venezuela

ExxonMobil s net year-end 2006 acreage holdings totaled 0.1 million onshore acres.

WORLDWIDE EXPLORATION

At year-end 2006, exploration activities were underway in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 37.4 million net acres were held at year-end 2006, and 2.0 net exploration wells were completed during the year in these countries.

Information with regard to mining activities follows:

Syncrude Operations

Syncrude is a joint-venture established to recover shallow deposits of oil 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 1.7 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 oil sands and produce synthetic crude oil from approved development areas on oil sands leases. Syncrude holds eight oil sands leases covering approximately 248,300 acres in the Athabasca Oil Sands Deposit which were issued by the Province of Alberta. The leases are automatically renewable as long as oil 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. The Base mine (lease 17) has now

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been mined out and only remnants are now being removed using trucks and shovels. 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 separate crude bitumen from sand, are capable of processing approximately 740,000 tons of oil sands a day, producing 150 million barrels of crude bitumen a year. This represents recovery capability of about 93 percent of the crude bitumen contained in the mined oil sands.

Crude bitumen extracted from oil sands is refined to a marketable hydrocarbon product through a combination of carbon removal in three large, high-temperature, fluid-coking vessels and by hydrogen addition in high-temperature, high-pressure, hydrocracking vessels. These processes remove carbon and sulfur and reformulate the crude into a low viscosity, low sulfur, high-quality synthetic crude oil product. In 2006, this upgrading process yielded 0.849 barrels of synthetic crude oil per barrel of crude bitumen. In 2006 about 44 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 56 percent was pipelined to refineries in eastern Canada and exported, primarily to the United States. Electricity is provided to Syncrude by a 270 megawatt electricity generating plant and a 160 megawatt electricity generating plant, both located at Syncrude. The generating plants are owned by the Syncrude participants. Recycled water is the primary water source, and incremental raw water is drawn, under license, from the Athabasca River. 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 $2.9 billion at year-end 2006.

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, 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. In active mining areas, the approximate well spacing is 400 feet (150 wells per section) and in future mining areas, the well spacing is approximately 1,150 feet (20 wells per section). Proven reserves include the operating Base and North mines and the Aurora mine. In accordance with the approved mining plan, there are an estimated 1,845 million tons of extractable oil sands in the Base and North mines, with an average bitumen grade of 10.6 weight percent. In addition, at the Aurora mine, there are an estimated 4,580 million tons of extractable oil sands at an average bitumen grade of 11.2 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 2006 was equivalent to 718 million barrels of synthetic crude oil. Imperial s reserve assessment uses a 6 percent and 7 percent bitumen grade cut-off for the North mine and Aurora mine respectively, a 90 percent overall extraction recovery, a 97 percent mining dilution factor and an 88 percent upgrading yield.

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 increased upgrading capacity came on stream in 2006 and increased production capacity to 355 thousand barrels of synthetic crude oil per day (gross). Additional mining trains in the North mine and Aurora mine were also completed in 2005. There are no approved plans for major future expansion projects.

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ExxonMobil Share of Net Proven Syncrude Reserves(1)

	Synthetic Crude Oil		
	Base Mine and North Mine	Aurora Mine	Total
	(millions of barrels)		
January 1, 2006	208	530	738
Revision of previous estimate		1	1
Production	(9)	(12)	(21)
December 31, 2006	199	519	718

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

Syncrude Operating Statistics (total operation)

	2006	2005	2004	2003	2002
Operating Statistics					
Total mined overburden (millions of cubic yards)(1)	128.2	97.1	100.3	109.2	102.0
Mined overburden to oil sands ratio(1)	1.18	1.02	0.94	1.15	1.05
Oil sands mined (millions of tons)	195.5	168.0	188.0	168.0	172.1
Average bitumen grade (weight percent)	11.4	11.1	11.1	11.0	11.2
Crude bitumen in mined oil sands (millions of tons)	22.2	18.6	20.9	18.5	19.2
Average extraction recovery (percent)	90.3	89.1	87.3	88.6	89.9
Crude bitumen production (millions of barrels)(2)	111.6	94.2	103.3	92.3	97.8
Average upgrading yield (percent)	84.9	85.3	85.5	86.0	86.3
Gross synthetic crude oil produced (millions of barrels)	95.5	79.3	88.4	78.4	84.8
ExxonMobil net share (millions of barrels)(3)	21	19	22	19	21

(1) Includes pre-stripping of mine areas and reclamation volumes.
(2) Crude bitumen production is equal to crude bitumen in mined oil 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.***

As previously reported, the Puerto Rican Environmental Quality Board (EQB) issued an order on May 21, 2001, alleging that Esso Standard Oil Company (Puerto Rico) (Esso) failed to investigate and remediate alleged hydrocarbon contamination associated with underground storage tanks at a service station in Barranquitas, Puerto Rico. The EQB sought a penalty of $75.9 million. Esso filed a federal law suit challenging the constitutionality of the procedures used in the EQB administrative process related to the penalty assessment. In March 2005, the federal District Court in the suit concluded that the EQB proceeding was impermissibly biased against Esso and issued a preliminary injunction prohibiting the EQB from continuing its penalty hearing or imposing the $75.9 million penalty on Esso. On November 7, 2006, after granting Esso s motion for summary judgment, the District Court issued a permanent injunction that similarly prohibits EQB actions with respect to the penalty proceeding. The EQB may appeal this decision.

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As previously disclosed, the New York State Department of Environmental Conservation (NYSDEC) issued a Notice of Hearing and complaint on March 24, 2004, alleging that ExxonMobil Oil Corporation in whole or in part is responsible for a discharge of 17 million gallons of petroleum prior to 1978 in connection with past operations at its Brooklyn terminal. The NYSDEC also alleged that the Brooklyn terminal had numerous spills after 1978, in violation of New York Navigation Law. The NYSDEC sought natural resource damages. On June 19, 2006, the NYSDEC referred the matter to the New York State Attorney General (AG). On November 30, 2006, the NYSDEC advised the Administrative Law Judge that it was withdrawing the pending administrative enforcement case, without prejudice. On February 8, 2007, the AG issued two notices of intent to sue ExxonMobil in connection with its remedial activities at the Brooklyn terminal site. The first notice relates to alleged violations under the Clean Water Act. The State indicates it will seek civil penalties and injunctive relief for allegedly ongoing, unpermitted discharges of pollutants by the company into Newtown Creek. The second notice relates to alleged violations of the Resource Conservation and Recovery Act (RCRA) as a result of solid or hazardous waste contamination of soils, groundwater, and the surface waters and sediments of Newtown Creek. This notice names ExxonMobil and four unrelated entities as potential parties and indicates the State is seeking injunctive relief.

In another previously reported matter, Mobil Pipe Line Company (Mobil) agreed in January 2007 to sign a Consent Assessment of Civil Penalty issued by the Pennsylvania Department of Environmental Protection (PDEP) on May 11, 2006, pursuant to the Pennsylvania Clean Streams Law. This Consent Assessment resolves PDEP s allegations that Mobil discharged gasoline into the soil and groundwater in South Whitehall Township, Pennsylvania. The release allegedly occurred from a pipeline and also caused a fire beginning on February 1, 2005, and continuing until February 4, 2005. Mobil will pay a combined civil penalty and cost reimbursement amount of $122,000. This is full and final resolution of any existing or potential liability of Mobil to the PDEP for the incident at issue.

Regarding a previously disclosed matter, on January 26, 2007, ExxonMobil Oil Corporation and California s Department of Toxic Substances Control (DTSC) signed a Consent Order settling allegations made by the DTSC in a Summary of Violations issued to the Torrance Refinery in December 2003. The DTSC had alleged that the refinery had discharged wastewater containing soluble selenium above one part per million to the sewer that leads to the county treatment facility in violation of California hazardous waste rules. The Consent Order calls for the refinery to comply with the hazardous waste regulations as they relate to its discharge into the sewer of wastewater containing selenium and calls for the following payments totaling $650,000: administrative penalty - $350,000; supplemental environmental project - $150,000; reimbursement of DTSC costs - $100,000; and payment to the Western States Project Training Fund - $50,000.

Refer to the relevant portions of Note 15: Litigation and Other Contingencies 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 1, 2007	Title (Held Office Since)
R. W. Tillerson	54	Chairman of the Board (2006)
D. D. Humphreys	59	Senior Vice President (2006) and Treasurer (2004)
S. R. McGill	64	Senior Vice President (2004)
J. S. Simon	63	Senior Vice President (2004)
M. W. Albers	50	President, ExxonMobil Development Company (2004)
A. T. Cejka	55	Vice President (2004)
H. R. Cramer	56	Vice President (1999)
M. J. Dolan	53	Vice President (2004)
M. E. Foster	63	Vice President (2004)
H. H. Hubble	54	Vice President Investor Relations and Secretary (2004)
G. L. Kohlenberger	54	Vice President (2002)
C. W. Matthews	62	Vice President and General Counsel (1995)
P. T. Mulva	55	Vice President and Controller (2004)
S. D. Pryor	57	Vice President (2004)
P. E. Sullivan	63	Vice President and General Tax Counsel (1995)
A. P. Swiger	50	Vice President (2006)

For at least the past five years, Messrs. Cramer, Humphreys, Kohlenberger, Matthews, McGill, Simon, Sullivan and Tillerson have been employed as executives of the registrant. Mr. Tillerson was a Senior Vice President and then President, a title he continues to hold, before becoming Chairman of the Board. Mr. Humphreys was Vice President and Controller and then Vice President and Treasurer before becoming Senior Vice President and Treasurer. Mr. McGill was President of ExxonMobil Production Company before becoming Senior Vice President. Mr. Simon was President of ExxonMobil Refining & Supply Company before becoming Senior Vice President. Mr. Mulva was Vice President Investor Relations and Secretary before becoming Vice President and Controller.

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, 2006.

Esso Exploration and Production Chad Inc.	Albers and Swiger
Exxon Azerbaijan Caspian Sea Limited	Swiger
Exxon Azerbaijan Limited	Swiger
ExxonMobil Chemical Company	Dolan and Pryor
ExxonMobil Development Company	Albers and Foster
ExxonMobil Exploration Company	Cejka
ExxonMobil Fuels Marketing Company	Cramer
ExxonMobil Gas & Power Marketing Company	Swiger
ExxonMobil Lubricants & Petroleum Specialties Company	Kohlenberger
ExxonMobil Production Company	Foster and Swiger
ExxonMobil Refining & Supply Company	Dolan, Hubble and Pryor
ExxonMobil Saudi Arabia	Dolan
Imperial Oil Limited	Mulva

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, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Reference is made to the Quarterly Information portion of the Financial Section of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2006

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October, 2006	40,782,542	68.67	40,782,542	
November, 2006	37,276,243	73.33	37,276,243	
December, 2006	36,773,679	76.59	36,773,679	
Total	114,832,464	72.72	114,832,464	(See note 1)

Note 1 On August 1, 2000, the Corporation announced its intention to resume purchases of shares of its common stock for the treasury both to offset shares issued in conjunction with company benefit plans and programs and to gradually reduce the number of shares outstanding. The announcement did not specify an amount or expiration date. The Corporation has continued to purchase shares since this announcement and to report purchased volumes in its quarterly earnings releases. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice.

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Item 6. ***Selected Financial Data.***

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(millions of dollars, except per share amounts)				
Sales and other operating revenue(1)(2)	$ 365,467	$ 358,955	$ 291,252	$ 237,054	$ 200,949
(1) Sales-based taxes included.	*$ 30,381*	*$ 30,742*	*$ 27,263*	*$ 23,855*	*$ 22,040*
(2) Includes amounts for purchases/sales contracts with the same counterparty for 2002-2005.					
Net income					
Income from continuing operations	$ 39,500	$ 36,130	$ 25,330	$ 20,960	$ 11,011
Discontinued operations, net of income tax					449
Cumulative effect of accounting change, net of income tax				550	
Net income	$ 39,500	$ 36,130	$ 25,330	$ 21,510	$ 11,460
Net income per common share					
Income from continuing operations	$ 6.68	$ 5.76	$ 3.91	$ 3.16	$ 1.62
Discontinued operations, net of income tax					0.07
Cumulative effect of accounting change, net of income tax				0.08	
Net income	$ 6.68	$ 5.76	$ 3.91	$ 3.24	$ 1.69
Net income per common share - assuming dilution					
Income from continuing operations	$ 6.62	$ 5.71	$ 3.89	$ 3.15	$ 1.61
Discontinued operations, net of income tax					0.07
Cumulative effect of accounting change, net of income tax				0.08	
Net income	$ 6.62	$ 5.71	$ 3.89	$ 3.23	$ 1.68
Cash dividends per common share	$ 1.28	$ 1.14	$ 1.06	$ 0.98	$ 0.92
Total assets	$ 219,015	$ 208,335	$ 195,256	$ 174,278	$ 152,644
Long-term debt	$ 6,645	$ 6,220	$ 5,013	$ 4,756	$ 6,655

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 in the Financial Section of this report.

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

Reference is made to the section entitled Market Risks, Inflation and Other Uncertainties , excluding the part entitled Inflation and Other Uncertainties, in 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 28, 2007, beginning with the section entitled Report of Independent Registered Public Accounting Firm and continuing through Note 18: Income, Sales-Based and Other Taxes;

Quarterly Information (unaudited);

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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*.**

Management s Evaluation of Disclosure Controls and Procedures

As indicated in the certifications in Exhibit 31 of this report, the Corporation s chief executive officer, principal financial officer and principal accounting officer have evaluated the Corporation s disclosure controls and procedures as of December 31, 2006. Based on that evaluation, these officers have concluded that the Corporation s disclosure controls and procedures are effective in ensuring that material information required to be in this annual report is accumulated and communicated to them on a timely basis.

Management s Report on Internal Control over Financial Reporting

Management, including the Corporation s chief executive officer, principal financial officer and principal accounting officer, is responsible for establishing and maintaining adequate internal control over the Corporation s financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation s internal control over financial reporting was effective as of December 31, 2006.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report included in the Financial Section of this report.

Changes in Internal Control over Financial Reporting

There were no changes during the Corporation s last fiscal quarter that materially affected, or are reasonably likely to materially affect the Corporation s internal control over financial reporting.

Item 9B. ***Other Information*.**

None.

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PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

Incorporated by reference to the following from the registrant s definitive proxy statement for the 2007 annual meeting of shareholders (the 2007 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 and the membership table of the portion entitled Board Meetings and Committees; Annual Meeting Attendance of the section entitled Corporate Governance .

Item 11. *Executive Compensation.*

Incorporated by reference to the sections entitled Director Compensation, Compensation Committee Report, Compensation Discussion and Analysis and Executive Compensation Tables of the registrant s 2007 Proxy Statement.

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

The information required under Item 403 of Regulation S-K is incorporated by reference to the section entitled Director and Executive Officer Stock Ownership of the registrant s 2007 Proxy Statement.

Equity Compensation Plan Information

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights [(1)]	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]

Equity compensation plans approved by security holders	104,121,419 (2)(3)	$40.18(3)	180,608,026(3)(4)(5)
Equity compensation plans not approved by security holders	0	0	0
Total	104,121,419	$40.18	180,608,026

(1) The exercise price of each option reflected in this table is equal to the fair market value of the Company s common stock on the date the option was granted. The weighted-average price reflects six prior option grants that are still outstanding.

(2) Includes 97,034,844 options granted under the 1993 Incentive Program and 7,086,575 restricted stock units to be settled in shares.

(3) Does not include options that ExxonMobil assumed in the 1999 merger with Mobil. At year-end 2006, the number of securities to be issued upon exercise of outstanding options under Mobil plans was 13,452,414, and the weighted-average exercise price of such options was $29.36. No additional awards may be made under those plans.

(4) Available shares can be granted in the form of restricted stock, options, or other stock-based awards. Includes 179,704,826 shares available for award under the 2003 Incentive Program and 903,200 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.

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(5) Under the 2004 Non-Employee Director Restricted Stock Plan approved by shareholders in May 2004, and the related standing resolution adopted by the Board, each non-employee director automatically receives 8,000 shares of restricted stock when first elected to the Board and, if the director remains in office, an additional 4,000 restricted shares each following year. While on the Board, each non-employee director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the shares. The restricted shares can be forfeited if the director leaves the Board early.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The registrant has concluded that it has no disclosable matters under Item 404(a) of Regulation S-K. Additional information required under this Item 13 is incorporated by reference to the portions entitled Related Person Transactions and Procedures and Director Independence of the section entitled Corporate Governance in the registrant s 2007 Proxy Statement.

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

Incorporated by reference to the section entitled Ratification of Independent Auditors and the portion entitled Audit Committee of the section entitled Corporate Governance of the registrant s 2007 Proxy Statement.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

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

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

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FINANCIAL SECTION

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BUSINESS PROFILE

Financial	Earnings After Income Taxes 2006	Earnings After Income Taxes 2005	Average Capital Employed 2006	Average Capital Employed 2005	Return on Average Capital Employed 2006	Return on Average Capital Employed 2005	Capital and Exploration Expenditures 2006	Capital and Exploration Expenditures 2005
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	$ 5,168	$ 6,200	$ 13,940	$ 13,491	37.1	46.0	$ 2,486	$ 2,142
Non-U.S.	21,062	18,149	43,931	39,770	47.9	45.6	13,745	12,328
Total	$ 26,230	$ 24,349	$ 57,871	$ 53,261	45.3	45.7	$ 16,231	$ 14,470
Downstream								
United States	$ 4,250	$ 3,911	$ 6,456	$ 6,650	65.8	58.8	$ 824	$ 753
Non-U.S.	4,204	4,081	17,172	18,030	24.5	22.6	1,905	1,742
Total	$ 8,454	$ 7,992	$ 23,628	$ 24,680	35.8	32.4	$ 2,729	$ 2,495
Chemical								
United States	$ 1,360	$ 1,186	$ 4,911	$ 5,145	27.7	23.1	$ 280	$ 243
Non-U.S.	3,022	2,757	8,272	8,919	36.5	30.9	476	411
Total	$ 4,382	$ 3,943	$ 13,183	$ 14,064	33.2	28.0	$ 756	$ 654
Corporate and financing	434	(154)	27,891	24,956			139	80
Total	$ 39,500	$ 36,130	$ 122,573	$ 116,961	32.2	31.3	$ 19,855	$ 17,699

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

Operating	2006	2005
	(thousands of barrels daily)	
Net liquids production		
United States	414	477
Non-U.S.	2,267	2,046
Total	2,681	2,523
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	1,625	1,739
Non-U.S.	7,709	7,512

Total	9,334	9,251
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production *(1)*	4,237	4,065
	(thousands of barrels daily)	
Petroleum product sales *(2)*		
United States	2,729	2,822
Non-U.S.	4,518	4,697
Total	7,247	7,519
	(thousands of barrels daily)	
Refinery throughput		
United States	1,760	1,794
Non-U.S.	3,843	3,929
Total	5,603	5,723
	(thousands of metric tons)	
Chemical prime product sales		
United States	10,703	10,369
Non-U.S.	16,647	16,408
Total	27,350	26,777

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.
(2) Petroleum product sales data is reported net of purchases/sales contracts with the same counterparty.

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FINANCIAL SUMMARY

	2006	2005	2004	2003	2002
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1) (2)*	$ 365,467	$ 358,955	$ 291,252	$ 237,054	$ 200,949
Earnings					
Upstream	$ 26,230	$ 24,349	$ 16,675	$ 14,502	$ 9,598
Downstream	8,454	7,992	5,706	3,516	1,300
Chemical	4,382	3,943	3,428	1,432	830
Corporate and financing	434	(154)	(479)	1,510	(442)
Merger-related expenses					(275)
Income from continuing operations	$ 39,500	$ 36,130	$ 25,330	$ 20,960	$ 11,011
Discontinued operations					449
Accounting change				550	
Net income	$ 39,500	$ 36,130	$ 25,330	$ 21,510	$ 11,460
Net income per common share					
Income from continuing operations	$ 6.68	$ 5.76	$ 3.91	$ 3.16	$ 1.62
Net income per common share assuming dilution					
Income from continuing operations	$ 6.62	$ 5.71	$ 3.89	$ 3.15	$ 1.61
Discontinued operations, net of income tax					0.07
Cumulative effect of accounting change, net of income tax				0.08	
Net income	$ 6.62	$ 5.71	$ 3.89	$ 3.23	$ 1.68
Cash dividends per common share	$ 1.28	$ 1.14	$ 1.06	$ 0.98	$ 0.92
Net income to average shareholders equity (percent)	35.1	33.9	26.4	26.2	15.5
Working capital	$ 26,960	$ 27,035	$ 17,396	$ 7,574	$ 5,116
Ratio of current assets to current liabilities	1.55	1.58	1.40	1.20	1.15
Additions to property, plant and equipment	$ 15,462	$ 13,839	$ 11,986	$ 12,859	$ 11,437
Property, plant and equipment, less allowances	$ 113,687	$ 107,010	$ 108,639	$ 104,965	$ 94,940
Total assets	$ 219,015	$ 208,335	$ 195,256	$ 174,278	$ 152,644
Exploration expenses, including dry holes	$ 1,181	$ 964	$ 1,098	$ 1,010	$ 920
Research and development costs	$ 733	$ 712	$ 649	$ 618	$ 631
Long-term debt	$ 6,645	$ 6,220	$ 5,013	$ 4,756	$ 6,655
Total debt	$ 8,347	$ 7,991	$ 8,293	$ 9,545	$ 10,748
Fixed-charge coverage ratio (times)	46.3	50.2	36.1	30.8	13.8
Debt to capital (percent)	6.6	6.5	7.3	9.3	12.2
Net debt to capital (percent) *(3)*	(20.4)	(22.0)	(10.7)	(1.2)	4.4
Shareholders equity at year end	$ 113,844	$ 111,186	$ 101,756	$ 89,915	$ 74,597
Shareholders equity per common share	$ 19.87	$ 18.13	$ 15.90	$ 13.69	$ 11.13
Weighted average number of common shares outstanding (millions)	5,913	6,266	6,482	6,634	6,753

Number of regular employees at year end (thousands) *(4)*	82.1	83.7	85.9	88.3	92.5
CORS employees not included above (thousands) *(5)*	24.3	22.4	19.3	17.4	16.8

(1) Sales and other operating revenue includes sales-based taxes of $30,381 million for 2006, $30,742 million for 2005, $27,263 million for 2004, $23,855 million for 2003 and $22,040 million for 2002.

(2) Sales and other operating revenue includes $30,810 million for 2005, $25,289 million for 2004, $20,936 million for 2003 and $18,150 million for 2002 for purchases/sales contracts with the same counterparty. Associated costs were included in Crude oil and product purchases. Effective January 1, 2006, these purchases/sales were recorded on a net basis with no resulting impact on net income. See note 1, Summary of Accounting Policies.

(3) Debt net of cash, excluding restricted cash. The ratio of net debt to capital including restricted cash is (26.3) percent for 2006.

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

(5) 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 and 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 Corporation s assets and from the divesting of assets. The Corporation employs a long-standing and regular disciplined review process to ensure that all assets are contributing to the Corporation 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	**2006**	**2005**	**2004**
		(millions of dollars)	
Net cash provided by operating activities	$ 49,286	$ 48,138	$ 40,551
Sales of subsidiaries, investments and property, plant and equipment	3,080	6,036	2,754
Cash flow from operations and asset sales	$ 52,366	$ 54,174	$ 43,305

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	**2006**	**2005**	**2004**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	$ 219,015	$ 208,335	$ 195,256
Less liabilities and minority share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(47,115)	(44,536)	(39,701)
Total long-term liabilities excluding long-term debt and equity of minority and preferred shareholders in affiliated companies	(45,905)	(41,095)	(41,554)
Minority share of assets and liabilities	(4,948)	(4,863)	(5,285)
Add ExxonMobil share of debt-financed equity company net assets	2,808	3,450	3,914
Total capital employed	$ 123,855	$ 121,291	$ 112,630
Total corporate sources: debt and equity perspective			
Notes and loans payable	$ 1,702	$ 1,771	$ 3,280

Long-term debt	6,645	6,220	5,013
Shareholders equity	113,844	111,186	101,756
Less minority share of total debt	(1,144)	(1,336)	(1,333)
Add ExxonMobil share of equity company debt	2,808	3,450	3,914
Total capital employed	$ 123,855	$ 121,291	$ 112,630

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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 to make investment decisions.

Return on average capital employed	**2006**	**2005**	**2004**
		(millions of dollars)	
Net income	$ 39,500	$ 36,130	$ 25,330
Financing costs (after tax)			
Third-party debt	44	(1)	(137)
ExxonMobil share of equity companies	(156)	(144)	(185)
All other financing costs net	191	(295)	54
Total financing costs	79	(440)	(268)
Earnings excluding financing costs	$ 39,421	$ 36,570	$ 25,598
Average capital employed	$ 122,573	$ 116,961	$ 107,339
Return on average capital employed corporate total	32.2%	31.3%	23.8%

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QUARTERLY INFORMATION

	2006					2005				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
	(thousands of barrels daily)									
Production of crude oil and natural gas liquids	2,698	2,702	2,647	2,678	2,681	2,544	2,468	2,451	2,629	2,523
Refinery throughput	5,548	5,407	5,756	5,698	5,603	5,749	5,727	5,764	5,652	5,723
Petroleum product sales *(1)*	7,177	7,060	7,302	7,447	7,247	7,494	7,510	7,477	7,592	7,519
	(millions of cubic feet daily)									
Natural gas production available for sale	11,175	8,754	8,139	9,301	9,334	10,785	8,709	7,716	9,822	9,251
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production *(2)*	4,560	4,161	4,004	4,228	4,237	4,341	3,919	3,737	4,266	4,065
	(thousands of metric tons)									
Chemical prime product sales	6,916	6,855	6,752	6,827	27,350	6,938	6,592	6,955	6,292	26,777
Summarized financial data										
	(millions of dollars)									
Sales and other operating revenue *(3) (4)*	$ 86,317	96,024	96,268	86,858	365,467	$ 79,475	86,622	96,731	96,127	358,955
Gross profit *(5)*	$ 33,428	37,668	37,117	33,764	141,977	$ 31,525	32,962	35,336	36,841	136,664
Net income	$ 8,400	10,360	10,490	10,250	39,500	$ 7,860	7,640	9,920	10,710	36,130
Per share data										
	(dollars per share)									
Net income per common share	$ 1.38	1.74	1.79	1.77	6.68	$ 1.23	1.21	1.60	1.72	5.76
Net income per common share assuming dilution	$ 1.37	1.72	1.77	1.76	6.62	$ 1.22	1.20	1.58	1.71	5.71
Dividends per common share	$ 0.32	0.32	0.32	0.32	1.28	$ 0.27	0.29	0.29	0.29	1.14
Common stock prices										
High	$ 63.96	65.00	71.22	79.00	79.00	$ 64.37	61.74	65.96	63.89	65.96
Low	$ 56.42	56.64	61.63	64.84	56.42	$ 49.25	52.78	57.60	54.50	49.25

(1) Petroleum product sales data is reported net of purchases/sales contracts with the same counterparty.
(2) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.
(3) 2005 Sales and other operating revenue includes amounts for purchases/sales with the same counterparty. Associated costs were included in Crude oil and product purchases. Effective January 1, 2006, these purchases/sales were recorded on a net basis with no resulting impact on net income. See note 1, Summary of Accounting Policies.
(4) Includes amounts for sales-based taxes.
(5) 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 591,226 registered shareholders of ExxonMobil common stock at December 31, 2006. At January 31, 2007, the registered shareholders of ExxonMobil common stock numbered 589,553.

On January 31, 2007, the Corporation declared a $0.32 dividend per common share, payable March 9, 2007.

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

FUNCTIONAL EARNINGS	2006	2005	2004
	(millions of dollars, except per share amounts)		
Net income (U.S. GAAP)			
Upstream			
United States	$ 5,168	$ 6,200	$ 4,948
Non-U.S.	21,062	18,149	11,727
Downstream			
United States	4,250	3,911	2,186
Non-U.S.	4,204	4,081	3,520
Chemical			
United States	1,360	1,186	1,020
Non-U.S.	3,022	2,757	2,408
Corporate and financing	434	(154)	(479)
Net income	$ 39,500	$ 36,130	$ 25,330
Net income per common share	$ 6.68	$ 5.76	$ 3.91
Net income per common share assuming dilution	$ 6.62	$ 5.71	$ 3.89
Special items included in net income			
Non-U.S. Upstream			
Gain on Dutch gas restructuring	$	$ 1,620	$
U.S. Downstream			
Allapattah lawsuit provision	$	$ (200)	$ (550)
Non-U.S. Downstream			
Sale of Sinopec shares	$	$ 310	$
Non-U.S. Chemical			
Sale of Sinopec shares	$	$ 150	$
Joint venture litigation	$	$ 390	$
Corporate and financing			
Tax-related benefit	$ 410	$	$

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

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future results, including demand growth and energy source mix; capacity increases; production growth and mix; 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 in Item 1A of ExxonMobil s 2006 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, manufacturing 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. Our 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 88 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 are volatile on a short-term basis and depend on supply and demand, ExxonMobil s investment decisions are based on our long-term outlook, 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 risk-assessed near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Prices for crude oil, natural gas and refined products are based on corporate plan assumptions developed annually by major region 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 capital productivity.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2030, the world s population is expected to grow to 8 billion, approximately 25 percent higher than today s level. Coincident with this population increase, the Corporation expects worldwide economic growth to average just under 3 percent per year. This combination of population and economic growth should lead to a primary energy demand increase of approximately 60 percent by 2030 versus 2000. The vast majority (~80 percent) of the increase is expected to occur in developing countries.

As demand rises, energy efficiency will become increasingly important, with the pace of improvement likely to accelerate. This accelerated pace will probably result from expected improvements in personal transportation and power generation driven by the introduction of new technologies, as well as many other improvements that span the residential, commercial and industrial sectors. Oil, gas and coal are expected to remain the predominant energy sources with approximately 80 percent share of total energy. Oil and gas are expected to maintain close to a 60 percent share. These well-established fuel sources are the only ones with the versatility and scale to meet the majority of the world s growing energy needs. Nuclear power will likely be a growing option to meet electricity needs. Alternative fuels, such as solar and wind power, will grow rapidly, underpinned by government subsidies and mandates. But even with assumptions of robust 10 percent average annual growth, solar and wind are expected to represent just 1 percent of the total energy portfolio by 2030.

Demand for liquid fuels is expected to grow at 1.4 percent per year, primarily due to increasing transportation requirements, especially related to light- and heavy-duty vehicles. The global fleet of light-duty vehicles will increase significantly, with related demand partly offset by improvements in fuel economy. Natural gas and coal are expected to grow at 1.7 and 1.6 percent per year, respectively, driven by increased need for electric power generation. The Corporation expects the liquefied natural gas (LNG) market to increase nearly fourfold by 2030, with LNG imports helping to meet growing demand in Europe, North America and Asia. With equity positions in many of the largest remote gas accumulations in the world, the Corporation is positioned to benefit from its technological advances in gas liquefaction, transportation and regasification that enable distant gas supplies to reach markets economically.

The Corporation expects the world s oil and gas resource base to grow not only from new discoveries, but also from increases to known reserves. Technology will underpin these increases. The cost to develop these resources will be significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide through 2030 will be about \$300 billion per year, or \$8 trillion (measured in 2005 dollars) in total for 2005-2030.

Upstream

ExxonMobil continues to maintain a large portfolio of development and exploration opportunities, which enables the Corporation to be selective, optimizing total profitability and mitigating overall political and technical risks. As future development projects bring new production online, the Corporation expects a shift in the geographic mix of its production volumes between now and 2011. Oil and natural gas output from West Africa, the Caspian, the Middle East and Russia is expected to increase over the next five years based on current capital project execution plans. Currently, these growth areas account for 35 percent of the Corporation s production. By 2011, they are expected to generate about 50 percent of total volumes. The remainder of the Corporation s production is expected to be sourced from established areas, including Europe and North America.

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In addition to a changing geographic mix, there will also be a change in the type of opportunities from which volumes are produced. Nonconventional production utilizing specialized technology such as arctic technology, deepwater drilling and production systems, heavy oil recovery processes and LNG is expected to grow from about 30 to 40 percent of the Corporation s output between now and 2011. The Corporation s overall volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the period 2007-2011. However, actual volumes will vary from year to year due to timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, asset sales, weather events, price effects under production sharing contracts and other factors described in Item 1A of ExxonMobil s 2006 Form 10-K.

Downstream

The downstream industry environment remains very competitive. While refining margins in 2006 were strong, our long-term real inflation-adjusted refining margins have declined at a rate of about 1 percent per year over the past 20 years. The intense competition in the retail fuels market has similarly driven down real margins by about 4 percent per year. Global refining capacity is expected to grow at about 1 to 2 percent per year through 2010 with Asia Pacific expected to grow at more than 3 percent per year. ExxonMobil assets are well-positioned to supply the growing demand for petroleum products and our continuous focus on making our refineries more efficient and productive has resulted in significant capacity increases to help meet growing demand at a fraction of the cost of building a new refinery. Our capacity growth rate over the past 10 years at existing facilities has been the equivalent of building a new average-size refinery every three years.

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 global marketplace and are impacted by many factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, seasonality and weather and political climate.

The objectives of ExxonMobil s Downstream strategies are to position the Corporation to be the industry leader under a variety of market conditions. These strategies include maintaining best-in-class operations in all aspects of the business, maximizing value from leading-edge technology, capitalizing on integration with other ExxonMobil businesses, and providing high-quality, valued products and services to the Corporation s customers. ExxonMobil has an ownership interest in 40 refineries, located in 20 countries, with distillation capacity of 6.4 million barrels per day and lubricant basestock manufacturing capacity of about 150 thousand barrels per day. ExxonMobil s fuels and lubes marketing business portfolios include operations around the world, serving a globally diverse customer base. World-class scale and integration, industry-leading efficiency, leading-edge technology and respected brands enable ExxonMobil to take advantage of attractive emerging-growth opportunities around the globe.

Chemical

The strength of the global economy supported strong demand growth for petrochemicals in 2006. Strong economic and industrial production growth fueled increased demand in Asia Pacific, particularly China. North America recovered from the supply disruptions created by hurricanes Katrina and Rita, while European growth was moderate, similar to that of GDP. Overall global supply/demand balances tightened, supporting higher prices and margins despite higher feedstock costs.

ExxonMobil benefited from continued operational excellence, as well as a portfolio of products that 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, ExxonMobil Chemical also has a diverse portfolio of less-cyclical business lines. Chemical s competitive advantages are achieved through its business mix, broad geographic coverage, investment discipline, integration of chemical capacity with large refining complexes or Upstream gas processing, advantaged feedstock capabilities, leading proprietary technology and product application expertise.

REVIEW OF 2006 AND 2005 RESULTS

	2006	2005	2004

	(millions of dollars)		
Net income (U.S. GAAP)	$ 39,500	$ 36,130	$ 25,330

2006

Net income in 2006 of $39,500 million was the highest ever for the Corporation, up $3,370 million from 2005. Net income for 2006 included a $410 million gain from the recognition of tax benefits related to historical investments in non-U.S. assets.

Total assets at December 31, 2006, of $219 billion increased by approximately $11 billion from 2005, reflecting strong earnings and the Corporation s active investment program, particularly in the Upstream.

2005

Net income in 2005 of $36,130 million was up $10,800 million from 2004. Net income in 2005 included special items of $2,270 million, consisting of a $1,620 million gain related to the Dutch gas restructuring, a $460 million gain from the sale of the Corporation s stake in Sinopec, a $390 million gain from the resolution of joint venture litigation and a charge of $200 million relating to the Allapattah lawsuit provision. Net income in 2004 included a special charge of $550 million relating to Allapattah.

Total assets at December 31, 2005, of $208 billion increased by approximately $13 billion from 2004, reflecting strong earnings and the Corporation s active investment program, particularly in the Upstream.

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Upstream

	2006	2005	2004
	(millions of dollars)		
Upstream			
United States	$ 5,168	$ 6,200	$ 4,948
Non-U.S.	21,062	18,149	11,727
Total	$ 26,230	$ 24,349	$ 16,675

2006

Upstream earnings for 2006 totaled $26,230 million, an increase of $1,881 million from 2005, including a $1,620 million gain related to the Dutch gas restructuring in 2005. Higher liquids and natural gas realizations were partly offset by higher operating expenses. Oil-equivalent production increased 4 percent versus 2005, including the impact of divestment and entitlement effects. Excluding these impacts, total oil-equivalent production increased by 7 percent. Liquids production of 2,681 kbd (thousands of barrels per day) increased by 158 kbd from 2005. Production increases from new projects in West Africa and increased Abu Dhabi volumes were partly offset by mature field decline, entitlement effects and divestment impacts. Natural gas production of 9,334 mcfd (millions of cubic feet per day) increased 83 mcfd from 2005. Higher volumes from projects in Qatar were partly offset by mature field decline. Earnings from U.S. Upstream operations for 2006 were $5,168 million, a decrease of $1,032 million. Earnings outside the U.S. for 2006 were $21,062 million, an increase of $2,913 million, including a $1,620 million gain related to the Dutch gas restructuring in 2005.

2005

Upstream earnings totaled $24,349 million, including $1,620 million from a gain related to the Dutch gas restructuring. Absent this, Upstream earnings increased $6,054 million from 2004 due to higher liquids and natural gas realizations, partly offset by lower production volumes. Oil-equivalent production was down 4 percent versus 2004 including the impact of hurricanes Katrina and Rita, as well as divestment and entitlement effects. Excluding these impacts, total oil-equivalent production decreased by 1 percent. Liquids production of 2,523 kbd decreased by 48 kbd from 2004. Production increases from new projects in West Africa, the North Sea and North America were offset by natural field decline in mature areas, the impact of hurricanes Katrina and Rita, as well as divestment and entitlement effects. Natural gas production of 9,251 mcfd decreased 613 mcfd from 2004. Higher volumes from projects in Qatar, the North Sea and North America were offset by mature field decline, the impact of hurricanes Katrina and Rita, maintenance activity, lower European demand, as well as entitlement and divestment impacts. Improved earnings from both U.S. and non-U.S. Upstream operations were driven by higher liquids and natural gas realizations, partly offset by lower production volumes. Earnings from U.S. Upstream operations for 2005 were $6,200 million, an increase of $1,252 million. Earnings outside the U.S. for 2005, including the $1,620 million gain related to the Dutch gas restructuring, were $18,149 million, an increase of $6,422 million.

Downstream

	2006	2005	2004
	(millions of dollars)		
Downstream			
United States	$ 4,250	$ 3,911	$ 2,186
Non-U.S.	4,204	4,081	3,520

Total	$ 8,454	$ 7,992	$ 5,706

2006

Downstream earnings totaled $8,454 million, an increase of $462 million from 2005 including a $310 million gain for the 2005 Sinopec share sale and a special charge of $200 million related to the 2005 Allapattah lawsuit provision. Stronger worldwide refining and marketing margins were partly offset by lower refining throughput. Petroleum product sales of 7,247 kbd decreased from 7,519 kbd in 2005, primarily due to lower refining throughput and divestment impacts. Refinery throughput was 5,603 kbd compared with 5,723 kbd in 2005. U.S. Downstream earnings of $4,250 million increased by $339 million, including a 2005 special charge related to the Allapattah lawsuit provision. Non-U.S. Downstream earnings of $4,204 million were $123 million higher than 2005 earnings which included a gain for the Sinopec share sale.

2005

Downstream earnings totaled $7,992 million, including a gain of $310 million for the Sinopec share sale and a special charge of $200 million relating to the Allapattah lawsuit provision. Downstream earnings for 2004 also included a charge of $550 million for Allapattah. Absent these, Downstream earnings increased $1,626 million from 2004, reflecting stronger worldwide refining margins partly offset by weaker marketing margins. Petroleum product sales (net) of 7,519 kbd increased from 7,511 kbd in 2004. Refinery throughput was 5,723 kbd compared with 5,713 kbd in 2004. U.S. Downstream earnings of $3,911 million increased by $1,725 million, including the charges in both years related to Allapattah. Non-U.S. Downstream earnings of $4,081 million, including a gain for the Sinopec share sale, were $561 million higher than 2004.

Chemical

	2006	**2005**	**2004**
		(millions of dollars)	
Chemical			
United States	$ 1,360	$ 1,186	$ 1,020
Non-U.S.	3,022	2,757	2,408
Total	$ 4,382	$ 3,943	$ 3,428

2006

Chemical earnings totaled $4,382 million, an increase of $439 million from 2005, including a $390 million gain from the favorable resolution of joint venture litigation in 2005 and a $150 million gain for the 2005 Sinopec share sale. Increased 2006 earnings were driven by higher margins and increased sales volumes. Prime product sales were 27,350 kt (thousands of metric tons), an increase of 573 kt. 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 and sulfur volumes are excluded. U.S. Chemical earnings of $1,360 million increased by $174 million. Non-U.S. Chemical earnings of $3,022 million were $265 million

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higher than 2005 earnings, which included gains from the favorable resolution of joint venture litigation and the Sinopec share sale.

2005

Chemical earnings totaled $3,943 million, including a $390 million gain from the favorable resolution of joint venture litigation and $150 million from a gain on the Sinopec share sale. Absent these, Chemical earnings decreased $25 million from 2004 due to lower volumes, partly offset by higher worldwide margins. Prime product sales were 26,777 kt, a decrease of 1,011 kt from 2004, largely reflecting the impact of hurricanes Katrina and Rita. U.S. Chemical earnings of $1,186 million increased by $166 million. Non-U.S. Chemical earnings increased by $349 million to $2,757 million, including the impact of the gain from the resolution of the joint venture litigation of $390 million and a gain of $150 million on the Sinopec share sale.

Corporate and Financing

	2006	2005	2004
	(millions of dollars)		
Corporate and financing	$ 434	$ (154)	$ (479)

2006

The corporate and financing segment contributed $434 million to earnings in 2006, up $588 million from 2005, primarily due to a $410 million gain from tax benefits related to historical investments in non-U.S. assets and higher interest income.

2005

Corporate and financing expenses were $154 million compared with $479 million in 2004. The decrease of $325 million is mainly due to higher interest income.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2006	2005
	(millions of dollars)	
Net cash provided by/(used in)		
Operating activities	$ 49,286	$ 48,138
Investing activities	(14,230)	(10,270)
Financing activities	(36,210)	(26,941)
Effect of exchange rate changes	727	(787)
Increase/(decrease) in cash and cash equivalents	$ (427)	$ 10,140
	(Dec. 31)	
Cash and cash equivalents	$ 28,244	$ 28,671
Cash and cash equivalents restricted	4,604	4,604
Total cash and cash equivalents	$ 32,848	$ 33,275

Cash and cash equivalents were $28,244 million at the end of 2006, comparable to the prior year, as a net reduction from operating, investing and financing activities was partly offset by $727 million of positive foreign exchange effects from the general weakening of the U.S. dollar in 2006. Including restricted cash and cash equivalents of $4,604 million (see note 3 and note 15), total cash and cash equivalents were $32,848 million at the end of 2006. Cash and cash equivalents were $28,671 million at the end of 2005, an increase of $10,140 million from 2004, including $787 million of negative foreign exchange rate effects from the general strengthening of the U.S. dollar in 2005. Including restricted cash and cash equivalents of $4,604 million, total cash and cash equivalents were $33,275 million at the end of 2005. Cash flows from operating, investing and financing activities are discussed below. For additional details, see the Consolidated Statement of Cash Flows.

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.

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. After a period of production at plateau rates, it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Averaged over all our existing oil and gas fields and without new projects, ExxonMobil s entitlement production is expected to decline at approximately six percent per year through the end of the decade, consistent with recent historical performance. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, and age of the field. Furthermore, the Corporation s production entitlements for individual fields can vary with price and contractual terms.

The Corporation has long been successful at offsetting the effects of natural field decline through disciplined investments and anticipates similar results in the future. Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a variety of risks including project start-up timing, operational outages, reservoir performance, crude oil and natural gas prices, weather events, and regulatory changes. The Corporation s cash flows are also highly dependent on crude oil and natural gas prices.

The Corporation s financial strength, as evidenced by its AAA/Aaa debt rating, enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2006 were $19.9 billion, reflecting the Corporation s continued active investment program. The Corporation expects spending to continue in this range for the next several years, although actual spending could vary depending on progress of individual projects. 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 Corporation 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 cash flows from operating activities.

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Cash Flow from Operating Activities

2006

Cash provided by operating activities totaled $49.3 billion in 2006, a $1.1 billion increase from 2005. The major source of funds was net income of $39.5 billion, adjusted for the noncash provision of $11.4 billion for depreciation and depletion, both of which increased. The net timing effects of receipts of notes and accounts receivable, payments of accounts and other payables and contributions to pension funds in 2006 provided a partial offset.

2005

Cash provided by operating activities totaled $48.1 billion in 2005, a $7.6 billion increase from 2004. The major source of funds was net income of $36.1 billion, which increased $10.8 billion. The adjustment for the noncash provision for depreciation and depletion was $10.3 billion. Contributing to the increased level of cash provided by operating activities in 2005 was the net timing effects of receipts of notes and accounts receivable and payments of accounts and other payables in a rising price environment.

Cash Flow from Investing Activities

2006

Cash used in investing activities totaled $14.2 billion in 2006, $4.0 billion higher than 2005. Spending for property, plant and equipment increased $1.6 billion. Proceeds from the sales of subsidiaries, investments and property, plant and equipment of $3.1 billion in 2006 decreased $3.0 billion, reflecting a lower level of asset sales and the absence of almost $1.4 billion from the sale of the Corporation s interest in Sinopec in 2005.

2005

Cash used in investing activities totaled $10.3 billion in 2005, $4.6 billion lower than 2004. In 2004, the Corporation pledged $4.6 billion as bond collateral for a litigation appeal. Spending for property, plant and equipment increased $1.9 billion. Proceeds from the sales of subsidiaries, investments and property, plant and equipment of $6.0 billion in 2005 increased $3.3 billion, including almost $1.4 billion from the sale of the Corporation s interest in Sinopec.

Cash Flow from Financing Activities

2006

Cash used in financing activities was $36.2 billion, an increase of $9.3 billion from 2005, reflecting a higher level of purchases of ExxonMobil shares. Dividend payments on common shares increased to $1.28 per share from $1.14 per share and totaled $7.6 billion, a payout of 19 percent. Total consolidated short-term and long-term debt increased $0.3 billion to $8.3 billion at year-end 2006.

Shareholders equity increased $2.7 billion in 2006, to $113.8 billion, reflecting $39.5 billion of net income reduced by distributions to ExxonMobil shareholders of $7.6 billion of dividends and $25.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. Shareholders equity, and net assets and liabilities, increased $2.8 billion, representing the foreign exchange translation effects of stronger foreign currencies at the end of 2006 on ExxonMobil s operations outside the United States. Recognition of the Postretirement benefits reserves adjustment under Financial Accounting Standard No. 158 (see note 2) reduced shareholders equity by $6.5 billion.

During 2006, Exxon Mobil Corporation purchased 451 million shares of its common stock for the treasury at a gross cost of $29.6 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 6.6 percent from 6,133 million at the end of 2005 to 5,729 million at the end of 2006. 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.

2005

Cash used in financing activities was $26.9 billion, an increase of $8.7 billion from 2004, reflecting a higher level of purchases of ExxonMobil shares. Dividend payments on common shares increased to $1.14 per share from $1.06 per share and totaled $7.2 billion, a payout of 20 percent. Total consolidated short-term and long-term debt declined $0.3 billion to $8.0 billion at year-end 2005.

Shareholders equity increased $9.5 billion in 2005, to $111.2 billion, reflecting $36.1 billion of net income partly offset by distributions to ExxonMobil shareholders of $7.2 billion of dividends and $16.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. Shareholders equity, and net assets and liabilities, decreased $2.6 billion, representing the foreign exchange translation effects of weaker foreign currencies at the end of 2005 on ExxonMobil s operations outside the United States.

During 2005, Exxon Mobil Corporation purchased 311 million shares of its common stock for the treasury at a gross cost of $18.2 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 4.2 percent from 6,401 million at the end of 2004 to 6,133 million at the end of 2005. Purchases were made in both the open market and through negotiated transactions.

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Commitments

Set forth below is information about the outstanding commitments of the Corporation s consolidated subsidiaries at December 31, 2006. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period			
Commitments	**Note Reference Number**	**2007**	**2008-2011**	**2012 and Beyond**	**Total**
		(millions of dollars)			
Long-term debt (1)	13	$	$ 684	$ 5,961	$ 6,645
Due in one year (2)		459			459
Asset retirement obligations (3)	8	266	1,167	3,270	4,703
Pension and other postretirement obligations (4)	16	1,318	3,144	10,002	14,464
Operating leases (5)	10	2,252	4,361	2,090	8,703
Unconditional purchase obligations (6)	15	587	1,797	1,599	3,983
Take-or-pay obligations (7)		780	2,474	2,036	5,290
Firm capital commitments (8)		5,024	2,823	1,186	9,033

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly after purchase, either in an active, highly liquid market or under long-term, unconditional sales contracts with similar pricing terms. Examples include long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at market prices. Inclusion of such commitments would not be meaningful in assessing liquidity and cash flow, because these purchases will be offset in the same periods by cash received from the related sales transactions.

Notes:

(1) Includes capitalized lease obligations of $220 million.

(2) The amount due in one year is included in notes and loans payable of $1,702 million (note 5).

(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 the benefit obligations exceeded the fair value of fund assets for certain U.S. and non-U.S. pension and other postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2007 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 $3,983 million mainly pertain to pipeline throughput agreements and include $2,039 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,127 million, was $2,856 million.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $5,290 million mainly pertain to pipeline and terminaling agreements and include $1,847 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,118 million, totaled $4,172 million.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $9.0 billion. These commitments were predominantly associated with Upstream projects outside the U.S., of which $3.2 billion was associated with LNG projects in Qatar and natural gas projects in Malaysia. The Corporation expects to fund the majority of these projects through internal cash flow.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2006, for $4,252 million, primarily relating to guarantees for notes, loans and performance under contracts (note 15). Included in this amount were guarantees by consolidated affiliates of $3,507 million, representing ExxonMobil s share of obligations of certain equity companies. The below-mentioned guarantees are not reasonably likely to have a material effect on the Corporation s financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

	Dec. 31, 2006		
	Equity Company Obligations	Other Third-Party Obligations	Total
		(millions of dollars)	
Total guarantees	$ 3,507	$ 745	$ 4,252

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Financial Strength

On December 31, 2006, unused credit lines for short-term financing totaled approximately $5.8 billion (note 5).

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 88 years.

	2006	2005	2004
Fixed-charge coverage ratio (times)	46.3	50.2	36.1
Debt to capital (percent)	6.6	6.5	7.3
Net debt to capital (percent) *(1)*	(20.4)	(22.0)	(10.7)
Credit rating	AAA/Aaa	AAA/Aaa	AAA/Aaa

(1) Debt net of cash, excluding restricted cash. The ratio of net debt to capital including restricted cash is (26.3) percent for 2006.

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.

The Corporation makes limited use of derivative instruments, which are discussed in note 12.

Litigation and Other Contingencies

As discussed in note 15, 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. All of the compensatory claims have been resolved and paid. All of the punitive damage claims were consolidated in the civil trial that began in 1994. The first judgment from the United States District Court for the District of Alaska in the amount of $5 billion was vacated by the United States Court of Appeals for the Ninth Circuit as being excessive under the Constitution. The second judgment in the amount of $4 billion was vacated by the Ninth Circuit panel without argument and sent back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm.* The most recent District Court judgment for punitive damages was for $4.5 billion plus interest and was entered in January 2004. The Corporation posted a $5.4 billion letter of credit. ExxonMobil and the plaintiffs appealed this decision to the Ninth Circuit, which ruled on December 22, 2006, that the award be reduced to $2.5 billion. On January 12, 2007, ExxonMobil petitioned the Ninth Circuit Court of Appeals for a rehearing en banc of its appeal. While it is reasonably possible that a liability for punitive damages may have been incurred from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

In December 2000, a jury in the 15th Judicial Circuit Court of Montgomery County, Alabama, returned a verdict against the Corporation in a dispute over royalties in the amount of $88 million in compensatory damages and $3.4 billion in punitive damages in the case of *Exxon Corporation v. State of Alabama, et al.* The verdict was upheld by the trial court in May 2001. In December 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and in November 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. In March 2004, the district court judge reduced the amount of punitive damages to $3.5 billion. ExxonMobil believes the judgment is not justified by the evidence, that any punitive damage award is not justified by either the facts or the law, and that the amount of the award is grossly excessive and unconstitutional. ExxonMobil has appealed the decision to the Alabama Supreme Court. The Alabama Supreme Court heard oral arguments on February 6, 2007. Management believes that the likelihood of the judgment 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. In May 2004, the Corporation posted a $4.5 billion supersedeas bond as required by Alabama law to stay execution of the judgment pending appeal. The Corporation has pledged to the issuer of the bond collateral consisting of cash and short-term, high-quality securities with an aggregate value of approximately $4.6 billion. This collateral is reported as restricted cash and cash equivalents on the Consolidated Balance Sheet. Under the terms of the pledge agreement, the Corporation is entitled to receive the income generated from the cash and securities and to make investment decisions, but is restricted from using the pledged cash and securities for any other purpose until such time the bond is canceled.

In 2001, a Louisiana state court jury awarded compensatory damages of $56 million and punitive damages of $1 billion to a landowner for damage caused by a third party that leased the property from the landowner. The third party provided pipe cleaning and storage services for the Corporation and other entities. The Louisiana Fourth Circuit Court of Appeals reduced the punitive damage award to $112 million in 2005. The Corporation appealed this decision to the Louisiana Supreme Court which, in March 2006, refused to hear the appeal. ExxonMobil has fully accrued and paid the compensatory and punitive damage awards. The Corporation appealed the punitive damage award to the U.S. Supreme Court, which on February 26, 2007, vacated the judgment and remanded the case to the Louisiana Fourth Circuit Court of Appeals for reconsideration in light of the recent U.S. Supreme Court decision in *Williams v. Phillip Morris USA*.

In *Allapattah v. Exxon*, a jury in the United States District Court for the Southern District of Florida determined in 2001 that a class of Exxon dealers between March 1983 and August 1994 had been overcharged for gasoline. In June 2003, the Eleventh Circuit Court of Appeals affirmed the judgment and in March 2004, denied a petition for a rehearing en banc. In October 2004, the U.S. Supreme Court granted review as to whether the class in the District Court judgment should include members that individually do not satisfy the $50,000 minimum amount-in-controversy requirement in federal court. In light of the Supreme Court s decision to grant review of only part of ExxonMobil s appeal, the Corporation took an after-tax charge of $550 million in the third quarter of 2004 reflecting the estimated liability, after considering potential set-offs and defenses for the claims under review by the Supreme Court. In June 2005, the Supreme Court granted the District Court the right to hear the claims of all class members and the Corporation took an after-tax charge of $200 million. The District Court has given final approval of a settlement of $1,075 million, pre-tax. This obligation has been fully accrued and was paid in the second quarter 2006.

Tax issues for 1989 to 1993 remain pending before the U.S. Tax 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.

CAPITAL AND EXPLORATION EXPENDITURES

	2006		2005	
	U.S.	**Non-U.S.**	**U.S.**	**Non-U.S.**
		(millions of dollars)		
Upstream *(1)*	$ 2,486	$ 13,745	$ 2,142	$ 12,328
Downstream	824	1,905	753	1,742
Chemical	280	476	243	411
Other	130	9	80	
Total	$ 3,720	$ 16,135	$ 3,218	$ 14,481

(1) Exploration expenses included.

Capital and exploration expenditures in 2006 were $19.9 billion, reflecting the Corporation s continued active investment program. The Corporation expects spending to continue in this range for the next several years. Actual spending could vary depending on the progress of individual projects.

Upstream spending was up 12 percent to $16.2 billion in 2006, from $14.5 billion in 2005, as a result of higher spending in growth areas such as Qatar, Abu Dhabi and West Africa. In addition, spending in the United States and the North Sea was also higher. During the past three years, Upstream capital and exploration expenditures averaged $14.1 billion. The majority of these expenditures are on development projects, which typically take two to four years from the time of recording proved undeveloped reserves to the start of production from those 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. Capital and exploration expenditures are not tracked by the undeveloped and developed proved reserve categories. Capital investments in the Downstream totaled $2.7 billion in 2006, up $0.2 billion from 2005. Chemical capital expenditures were up $0.1 billion from 2005.

TAXES

	2006	2005	2004
		(millions of dollars)	
Income taxes	$ 27,902	$ 23,302	$ 15,911
Sales-based taxes	30,381	30,742	27,263
All other taxes and duties	42,393	44,571	43,605
Total	$ 100,676	$ 98,615	$ 86,779
Effective income tax rate	43%	41%	40%

2006

Income, sales-based and all other taxes and duties totaled $100.7 billion in 2006, an increase of $2.1 billion or 2 percent from 2005. Income tax expense, both current and deferred, was $27.9 billion, $4.6 billion higher than 2005, reflecting higher pre-tax income in 2006. The effective tax rate was 43 percent in 2006, compared to 41 percent in 2005. During both periods, the Corporation continued to benefit from the favorable resolution of tax-related issues. Sales-based and all other taxes and duties of $72.8 billion in 2006 decreased $2.5 billion from 2005, reflecting the tax impact of net reporting of purchases and sales of inventory with the same counterparty, only partly offset by the effects of higher prices.

2005

Income, sales-based and all other taxes and duties totaled $98.6 billion in 2005, an increase of $11.8 billion or 14 percent from 2004. Income tax expense, both current and deferred, was $23.3 billion, $7.4 billion higher than 2004, reflecting higher pre-tax income in 2005. The effective tax rate was 41 percent in 2005, compared to 40 percent in 2004. During both periods, the Corporation continued to benefit from the favorable resolution of tax-related issues. Sales-based and all other taxes and duties of $75.3 billion in 2005 increased $4.4 billion from 2004, reflecting higher prices and foreign exchange effects.

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ENVIRONMENTAL MATTERS

Environmental Expenditures

	2006	2005
	(millions of dollars)	
Capital expenditures	$ 1,081	$ 1,240
Other expenditures	2,127	2,089
Total	$ 3,208	$ 3,329

Throughout ExxonMobil s businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as well as projects to reduce nitrogen oxide and sulfur oxide emissions and expenditures for asset retirement obligations. ExxonMobil s 2006 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil s share of equity company expenditures, were about $3.2 billion. The total cost for such activities is expected to remain in this range in 2007 and 2008 (with capital expenditures approximately 40 percent of the total).

Environmental Liabilities

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 multiparty 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 multiparty sites could mitigate ExxonMobil s actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil s operations or financial condition. Consolidated company provisions made in 2006 for environmental liabilities were $350 million ($487 million in 2005) and the balance sheet reflects accumulated liabilities of $864 million as of December 31, 2006, and $849 million as of December 31, 2005.

Asset Retirement Obligations

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 ($263 million for 2006). Over time, the liabilities are accreted for the increase in their present value, with this effect included in expenses ($243 million in 2006). Consolidated company expenditures for asset retirement obligations in 2006 were $238 million and the ending balance of the obligations recorded on the balance sheet at December 31, 2006, totaled $4,703 million.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2006	2005	2004
Crude oil and NGL ($/barrel)	$ 58.34	$ 48.23	$ 34.76
Natural gas ($/kcf)	6.08	5.96	4.48

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, based on the 2006 worldwide production levels, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $400 million annual after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a $0.10 per kcf change in the worldwide average gas realization would have approximately a $200 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide a broad indicator of changes in the earnings experienced in any particular period.

In the very competitive downstream and chemical environments, earnings are primarily determined by margin capture rather than absolute price levels of products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oil) and the market prices for the range of products produced. These prices in turn depend on global and regional supply/demand balances, inventory levels, refinery operations, import/export balances and weather.

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 at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 40 percent 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.

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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 over a broad range of future prices. 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 underperforming 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, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation s enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity. The Corporation s limited derivative activities pose no material credit or market risks to ExxonMobil s operations, financial condition or liquidity. Note 12 summarizes the fair value of derivatives outstanding at year end and the gains or losses that have been recognized in net income.

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 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. The Corporation s cash balances exceeded total debt at year-end 2006 and 2005.

The Corporation conducts business in many foreign currencies and is subject to exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil s geographically and functionally diverse operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts, commodity forwards, swaps and futures contracts to mitigate the impact of changes in currency values and commodity prices. Exposures related to the Corporation s limited use of the above contracts are 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 generally been countered by cost reductions from efficiency and productivity improvements. Increased global demand for certain services and materials has resulted in higher operating and capital costs in recent years. The Corporation continues to mitigate these effects through its economies of scale in global procurement and its efficient project management practices.

RECENTLY ISSUED STATEMENTS OF FINANCIAL ACCOUNTING STANDARDS

Accounting for Uncertainty in Income Taxes

In June 2006 the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes. FIN 48 is an interpretation of FASB Statement No. 109, Accounting for Income Taxes, and must be adopted by the Corporation no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that the company has taken or expects to take in its returns. The Corporation expects to recognize a transition gain of approximately $0.3 billion in shareholders equity upon adoption of FIN 48 in the first quarter of 2007. This gain reflects the recognition of several refund claims, partly offset by increased liability reserves.

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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 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 for calculating unit-of-production depreciation rates and for evaluating 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 include probable reserves. Probable reserves are reserves that are more 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, commercial and market assessment, and detailed analysis of well information such as flow rates and reservoir pressure declines. The estimation of proved reserves is controlled by the Corporation through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals (assisted by a central reserves group with significant technical experience), culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation.

Key features of the reserves estimation process include:

- rigorous peer-reviewed technical evaluations and analysis of well and field performance information (such as flow rates and reservoir pressure declines) and

- a requirement that management make significant funding commitments toward the development of the reserves prior to booking.

Although the Corporation is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and gas price levels.

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 (including both consolidated and equity company reserves), indicating that proved reserves are consistently moved from undeveloped to developed status. Over time, these undeveloped reserves will be reclassified to the developed category as new 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 proved reserves to the start of production from these reserves.

Beginning in 2004, the year-end reserves volumes as well as the reserves change categories shown in the proved reserves tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. Regulations preclude the Corporation from showing in this document the reserves that are calculated in a manner that is consistent with the basis that the Corporation uses to make its investment decisions. The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The Corporation believes that this approach is inconsistent with the long-term nature of the upstream business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the Corporation and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in year-end prices and costs that are used in the determination of reserves. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy 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. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method. 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.

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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 actual volumes produced to total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), applied to the 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. While the 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.

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. Trigger events for impairment evaluation 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 operating losses.

In general, the Corporation does not view temporarily low oil and gas prices as a trigger 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 significantly, 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 price assumptions developed in the annual planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. The corporate plan is a fundamental annual management process that is the basis for setting near-term risk-assessed operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Prices for natural gas and other products are based on corporate plan assumptions developed annually by major region 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 is provided following the notes to the financial statements. The standardized measure of discounted future cash flows is based on the year-end 2006 price applied for all future years, as required under Statement of Financial Accounting Standards No. 69 (FAS 69), Disclosure about Oil and Gas Producing Activities. 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.

Suspended Exploratory Well Costs

The Corporation carries as an asset exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Assessing whether a project has made sufficient progress is a subjective area and requires careful consideration of the relevant facts and circumstances. The facts and circumstances that support continued capitalization of suspended wells as of year-end 2006 are disclosed in note 9 to the financial statements.

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Consolidations

The Consolidated Financial Statements include the accounts of those significant subsidiaries that the Corporation controls. They also include the Corporation s share of the undivided interest in certain 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 identified as variable-interest entities in which it has less than a majority ownership, because of guarantees or other arrangements that create majority economic interests in those affiliates that 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 6.

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 its 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 of 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.

Pension Benefits

The Corporation and its affiliates sponsor approximately 100 defined benefit (pension) plans in about 50 countries. The funding arrangement for each plan depends on the prevailing practices and regulations of the countries where the Corporation operates. The Pension and Other Postretirement Benefits note provides details on pension obligations, fund assets and pension expense.

Some of these plans (primarily non-U.S.) provide pension benefits that 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 United States, 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 that differ from those used for accounting purposes.

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. Pension assumptions are reviewed annually by outside actuaries and senior 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 in 2006 was 9.0 percent. This compares to an actual rate of return over the past decade of 11 percent. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund 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 annual pension expense by approximately $120 million before tax.

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Differences between actual returns on fund assets versus the long-term expected return are not recognized in pension expense in the year that the difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees. Further details on pension accounting and related disclosures can be found in notes 2 and 16.

Litigation and Other Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits and tax disputes. Management has regular litigation and tax reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The status of significant claims is summarized in note 15.

GAAP requires that liabilities for contingencies be recorded when it is probable that a liability has been incurred by 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. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss.

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. Payments have not had a materially adverse effect on operations or financial condition. 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 Chemical operations use the local currency, except in highly inflationary countries (primarily in Latin America) and 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. Operations using the U.S. dollar as their functional currency include Malaysia, Indonesia, Angola, Nigeria, Equatorial Guinea, Russia and the Middle East.

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 REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation s chief executive officer, principal financial officer, and principal accounting officer, is responsible for establishing and maintaining adequate internal control over the Corporation s financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation s internal control over financial reporting was effective as of December 31, 2006.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Rex W. Tillerson	Donald D. Humphreys	Patrick T. Mulva
Chief Executive Officer	Sr. Vice President and Treasurer	Vice President and Controller
	(Principal Financial Officer)	(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Exxon Mobil Corporation:

We have completed integrated audits of Exxon Mobil Corporation s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed under Item 8 of the Form 10-K present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2006, and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements 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 defined benefit pension and other postretirement plans in 2006.

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Internal control over financial reporting

Also, in our opinion, management s assessment, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Corporation s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Dallas, Texas

February 28, 2007

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CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2006	2005	2004
		(millions of dollars)		
Revenues and other income				
Sales and other operating revenue *(1) (2)*		$ 365,467	$ 358,955	$ 291,252
Income from equity affiliates	6	6,985	7,583	4,961
Other income		5,183	4,142	1,822
Total revenues and other income		$ 377,635	$ 370,680	$ 298,035
Costs and other deductions				
Crude oil and product purchases		$ 182,546	$ 185,219	$ 139,224
Production and manufacturing expenses		29,528	26,819	23,225
Selling, general and administrative expenses		14,273	14,402	13,849
Depreciation and depletion		11,416	10,253	9,767
Exploration expenses, including dry holes		1,181	964	1,098
Interest expense		654	496	638
Sales-based taxes *(1)*	18	30,381	30,742	27,263
Other taxes and duties	18	39,203	41,554	40,954
Income applicable to minority and preferred interests		1,051	799	776
Total costs and other deductions		$ 310,233	$ 311,248	$ 256,794
Income before income taxes		$ 67,402	$ 59,432	$ 41,241
Income taxes	18	27,902	23,302	15,911
Net income		$ 39,500	$ 36,130	$ 25,330
Net income per common share (dollars)	11	$ 6.68	$ 5.76	$ 3.91
Net income per common share assuming dilution (dollars)	11	$ 6.62	$ 5.71	$ 3.89

(1) Sales and other operating revenue includes sales-based taxes of $30,381 million for 2006, $30,742 million for 2005 and $27,263 million for 2004.

(2) Sales and other operating revenue includes $30,810 million for 2005 and $25,289 million for 2004 for purchases/sales contracts with the same counterparty. Associated costs were included in Crude oil and product purchases. Effective January 1, 2006, these purchases/sales were recorded on a net basis with no resulting impact on net income. See note 1, Summary of Accounting Policies.

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2006	Dec. 31 2005
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		$ 28,244	$ 28,671
Cash and cash equivalents restricted	3, 15	4,604	4,604
Notes and accounts receivable, less estimated doubtful amounts	5	28,942	27,484
Inventories			
Crude oil, products and merchandise	3	8,979	7,852
Materials and supplies		1,735	1,469
Prepaid taxes and expenses		3,273	3,262
Total current assets		$ 75,777	$ 73,342
Investments and advances	7	23,237	20,592
Property, plant and equipment, at cost, less accumulated depreciation and depletion	8	113,687	107,010
Other assets, including intangibles, net		6,314	7,391
Total assets		$ 219,015	$ 208,335
Liabilities			
Current liabilities			
Notes and loans payable	5	$ 1,702	$ 1,771
Accounts payable and accrued liabilities	5	39,082	36,120
Income taxes payable		8,033	8,416
Total current liabilities		$ 48,817	$ 46,307
Long-term debt	13	6,645	6,220
Postretirement benefits reserves	16	13,931	10,220
Accrued liabilities		7,116	6,434
Deferred income tax liabilities	18	20,851	20,878
Deferred credits and other long-term obligations		4,007	3,563
Equity of minority and preferred shareholders in affiliated companies		3,804	3,527
Total liabilities		$ 105,171	$ 97,149
Commitments and contingencies	15		
Shareholders equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		$ 4,786	$ 4,477
Earnings reinvested		195,207	163,335
Accumulated other nonowner changes in equity			
Cumulative foreign exchange translation adjustment		3,733	979
Postretirement benefits reserves adjustment		(6,495)	
Minimum pension liability adjustment			(2,258)
Common stock held in treasury (2,290 million shares in 2006 and 1,886 million shares in 2005)		(83,387)	(55,347)

Total shareholders equity	$ 113,844	$ 111,186
Total liabilities and shareholders equity	$ 219,015	$ 208,335

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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CONSOLIDATED STATEMENT OF SHAREHOLDERS EQUITY

		2006		2005		2004	
	Note Reference Number	Shareholders Equity	Nonowner Changes in Equity*(1)*	Shareholders Equity	Nonowner Changes in Equity	Shareholders Equity	Nonowner Changes in Equity
				(millions of dollars)			
Common stock							
At beginning of year		$ 4,477		$ 4,053		$ 3,834	
Restricted stock amortization		480		356		173	
Tax benefits related to stock-based awards		169		224		183	
Other		(340)		(156)		(137)	
At end of year		$ 4,786		$ 4,477		$ 4,053	
Earnings reinvested							
At beginning of year		163,335		134,390		115,956	
Net income for the year		39,500	$ 39,500	36,130	$ 36,130	25,330	$ 25,330
Dividends common shares		(7,628)		(7,185)		(6,896)	
At end of year		$ 195,207		$ 163,335		$ 134,390	
Accumulated other nonowner changes in equity							
At beginning of year		(1,279)		1,527		(514)	
Foreign exchange translation adjustment		2,754	2,754	(2,619)	(2,619)	2,177	2,177
Postretirement benefits reserves adjustment	16	(6,495)					
Minimum pension liability adjustment	16	2,258	749	241	241	(53)	(53)
Unrealized gains/(losses) on stock investments						(83)	(83)
Reclassification adjustment for gain on sale of stock investment included in net income				(428)	(428)		
At end of year		$ (2,762)		$ (1,279)		$ 1,527	
Total			$ 43,003		$ 33,324		$ 27,371
Common stock held in treasury							
At beginning of year		(55,347)		(38,214)		(29,361)	
Acquisitions, at cost		(29,558)		(18,221)		(9,951)	
Dispositions		1,518		1,088		1,098	
At end of year		$ (83,387)		$ (55,347)		$ (38,214)	
Shareholders equity at end of year		$ 113,844		$ 111,186		$ 101,756	

Share Activity

	2006	2005	2004
		(millions of shares)	
Common stock			
Issued			
At beginning of year	8,019	8,019	8,019
Issued			
At end of year	8,019	8,019	8,019
Held in treasury			
At beginning of year	(1,886)	(1,618)	(1,451)
Acquisitions	(451)	(311)	(218)
Dispositions	47	43	51
At end of year	(2,290)	(1,886)	(1,618)
Common shares outstanding at end of year	5,729	6,133	6,401

(1) Includes pre-FAS 158 adoption change in minimum pension liability.
The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2006	2005	2004
			(millions of dollars)	
Cash flows from operating activities				
Net income				
Accruing to ExxonMobil shareholders		$ 39,500	$ 36,130	$ 25,330
Accruing to minority and preferred interests		1,051	799	776
Adjustments for noncash transactions				
Depreciation and depletion		11,416	10,253	9,767
Deferred income tax charges/(credits)		1,717	(429)	(1,134)
Postretirement benefits expense in excess of/(less than) payments		(1,787)	254	886
Accrued liability provisions in excess of/(less than) payments		(666)	398	806
Dividends received greater than/(less than) equity in current earnings of equity companies		(579)	(734)	(1,643)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) Notes and accounts receivable		(181)	(3,700)	(472)
Inventories		(1,057)	(434)	(223)
Prepaid taxes and expenses		(385)	(7)	11
Increase/(reduction) Accounts and other payables		1,160	7,806	6,333
Net (gain) on asset sales	4	(1,531)	(1,980)	(268)
All other items net		628	(218)	382
Net cash provided by operating activities		$ 49,286	$ 48,138	$ 40,551
Cash flows from investing activities				
Additions to property, plant and equipment		$ (15,462)	$ (13,839)	$ (11,986)
Sales of subsidiaries, investments and property, plant and equipment	4	3,080	6,036	2,754
Increase in restricted cash and cash equivalents	3, 15			(4,604)
Additional investments and advances		(2,604)	(2,810)	(2,287)
Collection of advances		756	343	1,213
Net cash used in investing activities		$ (14,230)	$ (10,270)	$ (14,910)
Cash flows from financing activities				
Additions to long-term debt		$ 318	$ 195	$ 470
Reductions in long-term debt		(33)	(81)	(562)
Additions to short-term debt		334	377	450
Reductions in short-term debt		(451)	(687)	(2,243)
Additions/(reductions) in debt with less than 90-day maturity		(95)	(1,306)	(66)
Cash dividends to ExxonMobil shareholders		(7,628)	(7,185)	(6,896)
Cash dividends to minority interests		(239)	(293)	(215)
Changes in minority interests and sales/(purchases) of affiliate stock		(493)	(681)	(215)
Tax benefits related to stock-based awards		462		
Common stock acquired		(29,558)	(18,221)	(9,951)
Common stock sold		1,173	941	960
Net cash used in financing activities		$ (36,210)	$ (26,941)	$ (18,268)

Effects of exchange rate changes on cash	$ 727	$ (787)	$ 532
Increase/(decrease) in cash and cash equivalents	$ (427)	$ 10,140	$ 7,905
Cash and cash equivalents at beginning of year	28,671	18,531	10,626
Cash and cash equivalents at end of year	$ 28,244	$ 28,671	$ 18,531

The information in the Notes to Consolidated Financial Statements 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 (Chemical) 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. Prior years data has been reclassified in certain cases to conform to the 2006 presentation basis.

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 certain upstream assets and liabilities. Additionally, the Corporation consolidates certain affiliates identified as variable-interest entities in which it has less than a majority ownership, because of guarantees or other arrangements that create majority economic interests in those affiliates that 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 ownership percentage 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 the Consolidated Statement of Shareholders Equity. Evidence of loss in value that might indicate impairment of investments in companies accounted for on the equity method is assessed to determine if such evidence represents a loss in value of the Corporation s investment that is other than temporary. Examples of key indicators include a history of operating losses, a negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee s business segment or geographic region. If evidence of an other than temporary loss in fair value below carrying amount is determined, an impairment is recognized. In the absence of market prices for the investment, discounted cash flows are used to assess fair value.

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 other producers are recognized on the basis of the Corporation s net working interest. Differences between actual production and net working interest volumes are not significant.

Effective January 1, 2006, the Corporation adopted the Emerging Issues Task Force (EITF) consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold. In prior periods, the Corporation recorded certain crude oil, natural gas, petroleum product and chemical sales and purchases contemporaneously negotiated with the same counterparty as revenues and purchases. As a result of the EITF consensus, the Corporation s accounts Sales and other operating revenue, Crude oil and product purchases and Other taxes and duties on the Consolidated Statement of Income were reduced in 2006 by associated amounts with no impact on net income. All operating segments are affected by this change, with the largest impact in the Downstream.

Sales-Based Taxes. The Corporation reports sales, excise and value-added taxes on sales transactions on a gross basis in the Consolidated Statement of Income (included in both revenues and costs). This gross reporting basis is footnoted on the Consolidated Statement of Income.

Derivative Instruments. The Corporation makes limited use of derivative instruments. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged 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 that arise from existing assets, liabilities and transactions.

The gains and losses resulting from changes in the fair value of derivatives are recorded in income. In some cases, the Corporation designates derivatives as fair value hedges, in which case the gains and losses are offset in income by the gains and losses arising from changes in the fair value of the underlying hedged items.

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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.

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.

Interest costs incurred to finance expenditures during the construction phase of multiyear projects are capitalized as part of the historical cost of acquiring the constructed assets. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Capitalized interest costs are included in property, plant and equipment and are depreciated over the service life of the related assets.

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. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method.

The Corporation carries as an asset exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. 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 in the Upstream segment. Unit-of-production rates are based on the amount of proved developed reserves of oil, gas and other minerals that are 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 are based on corporate plan assumptions developed annually by major region 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Asset Retirement Obligations and Environmental Liabilities. The Corporation incurs retirement obligations for certain assets at the time they are installed. The fair values of these obligations are recorded as liabilities on a discounted basis. The costs associated with these liabilities are capitalized as part of the related assets and depreciated. Over time, the liabilities are accreted for the change in their present value.

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 Corporation selects the functional reporting currency for its international subsidiaries based on the currency of the primary economic environment in which each subsidiary operates. Downstream and Chemical operations primarily use the local currency. However, the U.S. dollar is used in highly inflationary countries (primarily in Latin America) and Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations which are relatively self-contained and integrated within a particular country, such as Canada, the United Kingdom, Norway and continental Europe, use the local currency. Some Upstream operations, primarily in Asia, West Africa, Russia and the Middle East, use the U.S. dollar because they predominantly sell crude and natural gas production into U.S. dollar-denominated markets. For all operations, gains or losses from remeasuring foreign currency transactions into the functional currency are included in income.

Share-Based Payments. Effective January 1, 2006, the Corporation adopted the Financial Accounting Standards Board s revised Statement of Financial Accounting Standards No. 123 (FAS 123R), Share-Based Payment. FAS 123R requires compensation costs related to sharebased payments to be recognized in the income statement over the requisite service period. The amount of the compensation cost is to be measured based on the grant-date fair value of the instrument issued. FAS 123R is effective for awards granted or modified after the date of adoption and for awards granted prior to that date that have not vested. In 2003, the Corporation adopted a policy of expensing all share-based payments that is consistent with the provisions of FAS 123R, and all prior years outstanding stock option awards have vested. FAS 123R does not materially change the Corporation s existing accounting practices or the amount of share-based compensation recognized in earnings.

The Corporation has recognized restricted stock awards made prior to 2006 in compensation expense using the nominal vesting period approach. Under this method, the grant-date fair value of the awards has been amortized into compensation expense over the full vesting period of each award. For awards granted after the Corporation s adoption of FAS 123R on January 1, 2006, compensation expense is recognized using the nonsubstantive vesting period approach. Under this method, the value of the grants is amortized to compensation expense over the shorter of (1) the vesting period of each award or (2) the remaining time period until the employee becomes retiree eligible. Under both methods, the full unamortized value of awards for employees who retire before the end of the applicable amortization period is expensed. The impact of switching to the nonsubstantive vesting period approach is not material for the Corporation.

2. Accounting Changes for Defined Benefit Pension and Other Postretirement Plans

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (FAS 158), an amendment to FASB Statements No. 87, 88, 106 and 132(R). FAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit pension and other postretirement benefit plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other nonowner changes in equity. The standard also requires disclosure in the notes to the financial statements of additional information about certain effects on net periodic benefit costs of the next fiscal year that arise from delayed recognition of gains or losses, prior service costs and transition asset or obligation. FAS 158 was adopted by the Corporation in the financial statements for the year ending December 31, 2006. See note 16, Pension and Other Postretirement Benefits, for further details.

3. Miscellaneous Financial Information

Research and development costs totaled $733 million in 2006, $712 million in 2005 and $649 million in 2004.

Net income included aggregate foreign exchange transaction gains of $278 million in 2006, losses of $138 million in 2005 and gains of $69 million in 2004.

In 2006, 2005 and 2004, net income included gains of $401 million, $215 million and $227 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 $15.9 billion and $15.4 billion at December 31, 2006, and 2005, respectively.

Crude oil, products and merchandise as of year-end 2006 and 2005 consist of the following:

	2006	2005
	(billions of dollars)	
Petroleum products	$ 3.8	$ 3.2
Crude oil	2.8	2.2
Chemical products	2.1	2.1
Gas/other	0.3	0.3
Total	$ 9.0	$ 7.8

Restricted cash and cash equivalents were $4,604 million at December 31, 2006, attributable to cash and short-term, high-quality securities the Corporation pledged as collateral to the issuer of a $4.5 billion litigation-related bond. The Corporation posted this bond to stay execution of the judgment pending appeal in the case of *Exxon Corporation v. State of Alabama, et al.* (refer to note 15 for discussion of this lawsuit). Under the terms of the pledge agreement, the Corporation is entitled to receive the income generated from the cash and securities and to make investment decisions, but is restricted from using the pledged cash and securities for any other purpose until such time the bond is canceled.

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4. 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.

The Net (gain) on asset sales in net cash provided by operating activities on the Consolidated Statement of Cash Flows includes the before-tax gain from the Corporation s sale of its investment in Sinopec in 2005. Other gains are primarily from the sale of Upstream producing properties. These gains are reported in Other income on the Consolidated Statement of Income.

During 2005, Mobil Services (Bahamas) Ltd. issued variable notes due in 2035 to a consolidated ExxonMobil affiliate. This affiliate was later deconsolidated and the notes were classified as long-term debt. Therefore, this loan did not result in an Additions to long-term debt in the Consolidated Statement of Cash Flows.

	2006	2005	2004
	(millions of dollars)		
Cash payments for interest	$ 1,382	$ 473	$ 328
Cash payments for income taxes	$ 26,165	$ 22,535	$ 13,510

5. Additional Working Capital Information

	Dec. 31 2006	Dec. 31 2005
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $306 million and $321 million	$ 25,076	$ 23,858
Other, less reserves of $64 million and $44 million	3,866	3,626
Total	$ 28,942	$ 27,484
Notes and loans payable		
Bank loans	$ 753	$ 790
Commercial paper	274	291
Long-term debt due within one year	459	515
Other	216	175
Total	$ 1,702	$ 1,771
Accounts payable and accrued liabilities		
Trade payables	$ 25,084	$ 22,788
Payables to equity companies	2,597	2,451
Accrued taxes other than income taxes	6,052	5,607
Other	5,349	5,274
Total	$ 39,082	$ 36,120

On December 31, 2006, unused credit lines for short-term financing totaled approximately $5.8 billion. Of this total, $3.6 billion support commercial paper programs under terms negotiated when drawn. The weighted-average interest rate on short-term borrowings outstanding at December 31, 2006, and 2005, was 5.5 percent and 4.9 percent, respectively.

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6. 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 liquefied natural gas (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 24 percent, 22 percent and 22 percent in the years 2006, 2005 and 2004, respectively.

	2006		2005		2004	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	$ 98,542	$ 33,505	$ 88,003	$ 31,395	$ 72,872	$ 26,359
Income before income taxes	$ 24,094	$ 8,905	$ 24,070	$ 9,809	$ 15,278	$ 6,141
Income taxes	5,582	1,920	5,574	2,226	3,257	1,180
Net income	$ 18,512	$ 6,985	$ 18,496	$ 7,583	$ 12,021	$ 4,961
Current assets	$ 24,684	$ 8,484	$ 24,931	$ 8,645	$ 21,835	$ 7,803
Property, plant and equipment, less accumulated depreciation	59,691	19,602	50,622	17,149	46,236	15,793
Other long-term assets	7,209	4,206	6,900	3,919	6,600	4,166
Total assets	$ 91,584	$ 32,292	$ 82,453	$ 29,713	$ 74,671	$ 27,762
Short-term debt	$ 2,669	$ 888	$ 3,412	$ 1,179	$ 4,109	$ 1,348
Other current liabilities	16,543	5,852	15,330	5,414	14,463	5,397
Long-term debt	16,442	1,920	13,419	2,271	10,477	2,566
Other long-term liabilities	7,946	3,250	7,477	3,153	6,489	2,910
Advances from shareholders	15,791	6,803	14,390	5,580	12,339	3,799
Net assets	$ 32,193	$ 13,579	$ 28,425	$ 12,116	$ 26,794	$ 11,742

A list of significant equity companies as of December 31, 2006, together with the Corporation s percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	

Aera Energy LLC	48
BEB Erdgas und Erdoel GmbH	50
Cameroon Oil Transportation Company S.A.	41
Castle Peak Power Company Limited	60
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited II	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited II	30
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	45
Downstream	
Chalmette Refining, LLC	50
Saudi Aramco Lubricating Oil Refining Company Ltd.	30
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Holdings B.V.	50
Saudi Yanbu Petrochemical Co.	50

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7. Investments and Advances

	Dec. 31 2006	Dec. 31 2005
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	$ 13,579	$ 12,116
Advances	6,803	5,580
	$ 20,382	$ 17,696
Companies carried at cost or less and stock investments carried at fair value	1,678	1,732
	$ 22,060	$ 19,428
Long-term receivables and miscellaneous investments at cost or less	1,177	1,164
Total	$ 23,237	$ 20,592

8. Property, Plant and Equipment and Asset Retirement Obligations

	Dec. 31, 2006		Dec. 31, 2005	
Property, Plant and Equipment	**Cost**	**Net**	**Cost**	**Net**
	(millions of dollars)			
Upstream	$ 163,087	$ 68,410	$ 148,844	$ 62,817
Downstream	62,392	28,918	59,338	28,029
Chemical	22,197	9,319	21,055	9,304
Other	11,608	7,040	11,057	6,860
Total	$ 259,284	$ 113,687	$ 240,294	$ 107,010

In the Upstream segment, depreciation is on a unit-of-production basis, 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 Chemical segment, investments in process equipment are generally depreciated on a straight-line basis over a 20-year life.

Accumulated depreciation and depletion totaled $145,597 million at the end of 2006 and $133,284 million at the end of 2005. Interest capitalized in 2006, 2005 and 2004 was $530 million, $434 million and $500 million, respectively.

Asset Retirement Obligations (AROs)

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 their present value. Asset retirement obligations for downstream and chemical facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations.

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

	2006	2005
	(millions of dollars)	
Beginning balance	$ 3,568	$ 3,610
Accretion expense and other provisions	243	219
Reduction due to asset sales	(202)	(11)
Payments made	(238)	(193)
Liabilities incurred	263	165
Revisions	832	61
Foreign currency translation/other	237	(283)
Ending balance	$ 4,703	$ 3,568

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9. Accounting for Suspended Exploratory Well Costs

In accounting for suspended exploratory well costs, the Corporation utilizes Financial Accounting Standards Board Staff Position FAS 19-1 (FSP 19-1), Accounting for Suspended Well Costs. FSP 19-1 amended Statement of Financial Accounting Standards No. 19 (FAS 19), Financial Accounting and Reporting by Oil and Gas Producing Companies, to permit the continued capitalization of exploratory well costs beyond one year after the well is completed if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project.

The following two tables provide details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

Change in capitalized suspended exploratory well costs:

	2006	2005	2004
	(millions of dollars)		
Balance beginning at January 1	$ 1,139	$ 1,070	$ 1,093
Additions pending the determination of proved reserves	257	233	139
Charged to expense	(54)	(62)	(98)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(22)	(82)	(92)
Foreign exchange/other	(15)	(20)	28
Ending balance	$ 1,305	$ 1,139	$ 1,070
Ending balance attributed to equity companies included above	$ 17	$ 2	$ 1

Period end capitalized suspended exploratory well costs:

	2006	2005	2004
	(millions of dollars)		
Capitalized for a period of one year or less	$ 257	$ 233	$ 139
Capitalized for a period of between one and five years	566	485	510
Capitalized for a period of between five and ten years	213	167	172
Capitalized for a period of greater than ten years	269	254	249
Capitalized for a period greater than one year subtotal	$ 1,048	$ 906	$ 931
Total	$ 1,305	$ 1,139	$ 1,070

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a numerical breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months.

	2006	2005	2004
Number of projects with first capitalized well drilled in the preceding 12 months	13	16	8
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	53	56	61
Total	66	72	69

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Of the 53 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2006, 27 projects have drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 26 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 26 projects, which total $413 million.

Country/Project	Dec. 31, 2006	Years Wells Drilled	Comment
(millions of dollars)			
Angola			
Perpetua/Zinia/Acacia	$27	2000 -2005	Declarations of Commerciality for these discoveries were submitted from 2002 to 2005; alignment with co-venturers and government on development plan reached in 2005; initial project funding and engineering began in 2005.
Australia			
Kipper/East Pilchard	10	1986 - 2001	Bass Strait project in design phase; planned tie-in to existing platform; initial Kipper funding began in 2005 following execution of Memorandum of Understanding between co-venturers; development of East Pilchard phase awaiting capacity in existing/planned infrastructure.
Indonesia			
Cepu	41	1998 - 2001	Memorandum of Understanding and a Production Sharing Contract were signed in 2005 that extended the license term for 30 years followed by execution of a Joint Operating Agreement in 2006 that established ExxonMobil as the operator; initial project funding and engineering began in 2001; Plan of Development was approved by the government in 2006.
Natuna	118	1981 - 1983	Intent to proceed to the next phase of development communicated to government in 2004; discussions with government on near-term development work plans and contract terms are in progress; further technical evaluation and gas marketing activities continued to progress in 2006, including execution of a supplemental Memorandum of Understanding with a potential customer.
Kazakhstan			
Aktote	41	2003 - 2004	Development study under way to examine tieback to Kashagan field and/or potential development with Kairan field that is still in the exploration phase.
Nigeria			
Etoro-Isobo	9	2002	Offshore satellite development which will tie back to a planned production facility.
Other (5 projects)	15	2001 - 2002	Actively pursuing development of several additional offshore satellite discoveries which will tie back to existing/planned production facilities.
Norway			
Lavrans	21	1995 - 1999	Development awaiting capacity in existing/planned infrastructure; planned subsea tieback to existing floating production system; evaluation of phased ullage filling scenarios is progressing.
Skarv/Idun	30	1998 - 2002	Planned subsea tieback to floating production system; the export infrastructure and development plan were agreed to with partners in 2005; submission of Plan of Development to the government anticipated in 2007; initial project funding and engineering began in 2005.
Other (2 projects)	2	1992 - 2002	Progressing smaller North Sea developments.

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Country/Project	Dec. 31, 2006	Years Wells Drilled	Comment
	(millions of dollars)		
United Kingdom			
Phyllis	10	2004	Assessing co-development option with nearby 2005 Barbara discovery.
Puffin	42	1981 - 1986	Development awaiting capacity in existing infrastructure; planned tieback to existing U.K. North Sea production facility.
United States			
Point Thomson	28	1977 - 1980	A project team continues evaluating development options and has been working with the State of Alaska on North Slope gas transportation and production alternatives that include Point Thomson. Judicial appeals and lawsuits were filed challenging the decision of the Alaska Department of Natural Resources terminating the Point Thomson Unit.
Other			
Various (8 projects)	19	1979 - 2005	Projects primarily awaiting capacity in existing or planned infrastructure.
Total 2006 (26 projects)	$413		

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10. Leased Facilities

At December 31, 2006, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $8,703 million as indicated in the table. Estimated related rental income from noncancelable subleases is $218 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	(millions of dollars)	
2007	$ 2,252	$ 43
2008	1,794	38
2009	1,121	33
2010	845	30
2011	601	28
2012 and beyond	2,090	46
Total	$ 8,703	$ 218

Net rental expenses under both cancelable and noncancelable operating leases incurred during 2006, 2005 and 2004 were as follows:

	2006	2005	2004
	(millions of dollars)		
Rental expense	$ 3,576	$ 2,966	$ 2,627
Less sublease rental income	172	176	136
Net rental expense	$ 3,404	$ 2,790	$ 2,491

11. Earnings Per Share

	2006	2005	2004
Net income per common share			
Net income *(millions of dollars)*	$ 39,500	$ 36,130	$ 25,330
Weighted average number of common shares outstanding *(millions of shares)*	5,913	6,266	6,482
Net income per common share *(dollars)*	$ 6.68	$ 5.76	$ 3.91
Net income per common share assuming dilution			
Net income *(millions of dollars)*	$ 39,500	$ 36,130	$ 25,330
Weighted average number of common shares outstanding *(millions of shares)*	5,913	6,266	6,482
Effect of employee stock-based awards	57	56	37

Weighted average number of common shares outstanding assuming dilution	5,970	6,322	6,519
Net income per common share *(dollars)*	$ 6.62	$ 5.71	$ 3.89
Dividends paid per common share *(dollars)*	$ 1.28	$ 1.14	$ 1.06

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12. 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, 2006, and 2005, was $7.2 billion and $7.0 billion, respectively, as compared to recorded book values of $6.6 billion and $6.2 billion.

The Corporation s size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation s enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivatives to mitigate the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity. The Corporation s limited derivative activities pose no material credit or market risks to ExxonMobil s operations, financial condition or liquidity.

The estimated fair value of derivatives outstanding and recorded on the balance sheet was a net payable of $64 million at year-end 2006 and $426 million at year-end 2005, respectively. This is the amount that the Corporation would have paid to, or received from, third parties if these derivatives had been settled in the open market. The Corporation recognized a before-tax gain of $397 million, a loss of $312 million and a gain of $38 million related to derivatives during 2006, 2005 and 2004, respectively.

The fair value of derivatives outstanding at year-end 2006 and gain recognized during the year are immaterial in relation to the Corporation s year-end cash balance of $28.2 billion, total assets of $219.0 billion or net income for the year of $39.5 billion.

13. Long-Term Debt

At December 31, 2006, long-term debt consisted of $6,437 million due in U.S. dollars and $208 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 $459 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, 2007, in millions of dollars, are: 2008 $342, 2009 $119, 2010 $116 and 2011 $107. At December 31, 2006, the Corporation s unused long-term credit lines were not material.

Summarized long-term borrowings at year-end 2006 and 2005 were as shown in the table below:

	2006	2005
	(millions of dollars)	
Exxon Capital Corporation		
6.125% Guaranteed notes due 2008	$ 160	$ 160
SeaRiver Maritime Financial Holdings, Inc. *(1)*		
Guaranteed debt securities due 2008-2011 *(2)*	52	65
Guaranteed deferred interest debentures due 2012		
Face value net of unamortized discount plus accrued interest	1,550	1,391
Mobil Services (Bahamas) Ltd.		
Variable notes due 2035 *(3)*	972	972
Variable notes due 2034 *(4)*	311	311
Mobil Corporation		
8.625% debentures due 2021	248	248
Industrial revenue bonds due 2012-2039 *(5)*	1,697	1,700

Other U.S. dollar obligations *(6)*	1,275	1,023
Other foreign currency obligations	160	153
Capitalized lease obligations *(7)*	220	197
Total long-term debt	$ 6,645	$ 6,220

(1) Additional information is provided for this subsidiary on the following pages.
(2) Average effective interest rate of 5.1% in 2006 and 3.3% in 2005.
(3) Average effective interest rate of 5.1% in 2006 and 3.7% in 2005.
(4) Average effective interest rate of 5.1% in 2006 and 3.3% in 2005.
(5) Average effective interest rate of 3.7% in 2006 and 2.8% in 2005.
(6) Average effective interest rate of 6.2% in 2006 and 6.7% in 2005.
(7) Average imputed interest rate of 7.6% in 2006 and 7.5% in 2005.

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

Exxon Mobil Corporation has fully and unconditionally guaranteed the deferred interest debentures due 2012 ($1,550 million long-term debt at December 31, 2006) and the debt securities due 2007 to 2011 ($52 million long-term and $13 million short-term) of SeaRiver Maritime Financial Holdings, Inc.

SeaRiver Maritime Financial Holdings, Inc. is a 100-percent-owned subsidiary of Exxon Mobil Corporation.

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

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of income for 12 months ended December 31, 2006					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 16,317	$	$ 349,150	$	$ 365,467
Income from equity affiliates	37,911	14	6,974	(37,914)	6,985
Other income	944		4,239		5,183
Intercompany revenue	39,265	95	328,452	(367,812)	
Total revenues and other income	94,437	109	688,815	(405,726)	377,635
Costs and other deductions					
Crude oil and product purchases	37,365		491,169	(345,988)	182,546
Production and manufacturing expenses	7,357		27,120	(4,949)	29,528
Selling, general and administrative expenses	2,634		12,297	(658)	14,273
Depreciation and depletion	1,431		9,985		11,416
Exploration expenses, including dry holes	272		909		1,181
Interest expense	4,829	182	12,388	(16,745)	654
Sales-based taxes			30,381		30,381
Other taxes and duties	36		39,167		39,203
Income applicable to minority and preferred interests			1,051		1,051
Total costs and other deductions	53,924	182	624,467	(368,340)	310,233
Income before income taxes	40,513	(73)	64,348	(37,386)	67,402
Income taxes	1,013	(30)	26,919		27,902
Net income	$ 39,500	$ (43)	$ 37,429	$ (37,386)	$ 39,500

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	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of income for 12 months ended December 31, 2005					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 15,081	$	$ 343,874	$	$ 358,955
Income from equity affiliates	32,996	6	7,584	(33,003)	7,583
Other income	834		3,308		4,142
Intercompany revenue	33,546	56	274,757	(308,359)	
Total revenues and other income	82,457	62	629,523	(341,362)	370,680
Costs and other deductions					
Crude oil and product purchases	30,451		447,251	(292,483)	185,219
Production and manufacturing expenses	7,177		24,859	(5,217)	26,819
Selling, general and administrative expenses	2,434		12,480	(512)	14,402
Depreciation and depletion	1,341		8,912		10,253
Exploration expenses, including dry holes	137		827		964
Interest expense	2,723	159	7,790	(10,176)	496
Sales-based taxes			30,742		30,742
Other taxes and duties	21		41,533		41,554
Income applicable to minority and preferred interests			799		799
Total costs and other deductions	44,284	159	575,193	(308,388)	311,248
Income before income taxes	38,173	(97)	54,330	(32,974)	59,432
Income taxes	2,043	(36)	21,295		23,302
Net income	$ 36,130	$ (61)	$ 33,035	$ (32,974)	$ 36,130
Condensed consolidated statement of income for 12 months ended December 31, 2004					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 13,617	$	$ 277,635	$	$ 291,252
Income from equity affiliates	23,115	15	4,966	(23,135)	4,961
Other income	521		1,301		1,822
Intercompany revenue	24,147	22	196,686	(220,855)	
Total revenues and other income	61,400	37	480,588	(243,990)	298,035
Costs and other deductions					
Crude oil and product purchases	23,217		324,920	(208,913)	139,224
Production and manufacturing expenses	6,642		21,948	(5,365)	23,225
Selling, general and administrative expenses	2,099		12,060	(310)	13,849
Depreciation and depletion	1,424	1	8,342		9,767
Exploration expenses, including dry holes	187		911		1,098
Interest expense	1,381	135	5,360	(6,238)	638

Sales-based taxes			27,263		27,263
Other taxes and duties	14		40,940		40,954
Income applicable to minority and preferred interests			776		776
Total costs and other deductions	34,964	136	442,520	(220,826)	256,794
Income before income taxes	26,436	(99)	38,068	(23,164)	41,241
Income taxes	1,106	(40)	14,845		15,911
Net income	$ 25,330	$ (59)	$ 23,223	$ (23,164)	$ 25,330

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	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, 2006					
Cash and cash equivalents	$ 6,355	$	$ 21,889	$	$ 28,244
Cash and cash equivalents restricted			4,604		4,604
Notes and accounts receivable net	2,057		26,885		28,942
Inventories	1,213		9,501		10,714
Prepaid taxes and expenses	357		2,916		3,273
Total current assets	9,982		65,795		75,777
Investments and advances	200,982	359	409,935	(588,039)	23,237
Property, plant and equipment net	16,730		96,957		113,687
Other long-term assets	275	64	5,975		6,314
Intercompany receivables	16,501	1,883	435,221	(453,605)	
Total assets	$ 244,470	$ 2,306	$ 1,013,883	$ (1,041,644)	$ 219,015
Notes and loans payable	$ 90	$ 13	$ 1,599	$	$ 1,702
Accounts payable and accrued liabilities	3,025	1	36,056		39,082
Income taxes payable	548	1	7,484		8,033
Total current liabilities	3,663	15	45,139		48,817
Long-term debt	274	1,602	4,769		6,645
Deferred income tax liabilities	1,975	237	18,639		20,851
Other long-term liabilities	8,044		20,814		28,858
Intercompany payables	116,670	387	336,548	(453,605)	
Total liabilities	130,626	2,241	425,909	(453,605)	105,171
Earnings reinvested	195,207	(404)	144,607	(144,203)	195,207
Other shareholders equity	(81,363)	469	443,367	(443,836)	(81,363)
Total shareholders equity	113,844	65	587,974	(588,039)	113,844
Total liabilities and shareholders equity	$ 244,470	$ 2,306	$ 1,013,883	$ (1,041,644)	$ 219,015
Condensed consolidated balance sheet for year ended December 31, 2005					
Cash and cash equivalents	$ 12,076	$	$ 16,595	$	$ 28,671
Cash and cash equivalents restricted	4,604				4,604
Notes and accounts receivable net	2,183		25,301		27,484
Inventories	1,241		8,080		9,321
Prepaid taxes and expenses	117		3,145		3,262

Total current assets	20,221		53,121		73,342
Investments and advances	163,033	375	403,173	(545,989)	20,592
Property, plant and equipment net	15,537		91,473		107,010
Other long-term assets	1,257	74	6,060		7,391
Intercompany receivables	14,569	1,768	378,217	(394,554)	
Total assets	$ 214,617	$ 2,217	$ 932,044	$ (940,543)	$ 208,335
Notes and loans payable	$ 446	$ 10	$ 1,315	$	$ 1,771
Accounts payable and accrued liabilities	3,137	1	32,982		36,120
Income taxes payable	553	2	7,861		8,416
Total current liabilities	4,136	13	42,158		46,307
Long-term debt	270	1,456	4,494		6,220
Deferred income tax liabilities	2,909	257	17,712		20,878
Other long-term liabilities	5,412		18,332		23,744
Intercompany payables	90,705	383	303,466	(394,554)	
Total liabilities	103,432	2,109	386,162	(394,554)	97,149
Earnings reinvested	163,335	(361)	108,793	(108,432)	163,335
Other shareholders equity	(52,150)	469	437,089	(437,557)	(52,149)
Total shareholders equity	111,185	108	545,882	(545,989)	111,186
Total liabilities and shareholders equity	$ 214,617	$ 2,217	$ 932,044	$ (940,543)	$ 208,335

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	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of cash flows for 12 months ended December 31, 2006					
Cash provided by/(used in) operating activities	$ 3,678	$ 112	$ 47,111	$ (1,615)	$ 49,286
Cash flows from investing activities					
Additions to property, plant and equipment	(1,571)		(13,891)		(15,462)
Sales of long-term assets	421		2,659		3,080
Decrease/(increase) in restricted cash and cash equivalents	4,604		(4,604)		
Net intercompany investing	23,067	(107)	(23,091)	131	
All other investing, net			(1,848)		(1,848)
Net cash provided by/(used in) investing activities	26,521	(107)	(40,775)	131	(14,230)
Cash flows from financing activities					
Additions to short- and long-term debt			652		652
Reductions in short- and long-term debt		(10)	(474)		(484)
Additions/(reductions) in debt with less than 90-day maturity	(368)		273		(95)
Cash dividends	(7,628)		(1,615)	1,615	(7,628)
Common stock acquired	(29,558)				(29,558)
Net intercompany financing activity		5	126	(131)	
All other financing, net	1,634		(731)		903
Net cash provided by/(used in) financing activities	(35,920)	(5)	(1,769)	1,484	(36,210)
Effects of exchange rate changes on cash			727		727
Increase/(decrease) in cash and cash equivalents	$ (5,721)	$	$ 5,294	$	$ (427)
Condensed consolidated statement of cash flows for 12 months ended December 31, 2005					
Cash provided by/(used in) operating activities	$ 11,538	$ 129	$ 42,099	$ (5,628)	$ 48,138
Cash flows from investing activities					
Additions to property, plant and equipment	(1,296)		(12,543)		(13,839)
Sales of long-term assets	314		5,722		6,036
Decrease/(increase) in restricted cash and cash equivalents					
Net intercompany investing	15,483	(173)	(15,545)	235	
All other investing, net	1		(2,468)		(2,467)
Net cash provided by/(used in) investing activities	14,502	(173)	(24,834)	235	(10,270)
Cash flows from financing activities					

Additions to short- and long-term debt			572		572
Reductions in short- and long-term debt		(10)	(758)		(768)
Additions/(reductions) in debt with less than 90-day maturity	446		(1,752)		(1,306)
Cash dividends	(7,185)		(5,628)	5,628	(7,185)
Common stock acquired	(18,221)				(18,221)
Net intercompany financing activity		(21)	181	(160)	
All other financing, net	941	75	(974)	(75)	(33)
Net cash provided by/(used in) financing activities	(24,019)	44	(8,359)	5,393	(26,941)
Effects of exchange rate changes on cash			(787)		(787)
Increase/(decrease) in cash and cash equivalents	$ 2,021	$	$ 8,119	$	$ 10,140

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of cash flows for 12 months ended December 31, 2004					
Cash provided by/(used in) operating activities	$ 21,515	$ 44	$ 32,845	$ (13,853)	$ 40,551
Cash flows from investing activities					
Additions to property, plant and equipment	(1,101)		(10,885)		(11,986)
Sales of long-term assets	521		2,233		2,754
Decrease/(increase) in restricted cash and cash equivalents	(4,604)				(4,604)
Net intercompany investing	5,109	(55)	(5,129)	75	
All other investing, net	2		(1,076)		(1,074)
Net cash provided by/(used in) investing activities	(73)	(55)	(14,857)	75	(14,910)
Cash flows from financing activities					
Additions to short- and long-term debt			920		920
Reductions in short- and long-term debt	(1,146)	(10)	(1,649)		(2,805)
Additions/(reductions) in debt with less than 90-day maturity			(66)		(66)
Cash dividends	(6,896)		(13,853)	13,853	(6,896)
Common stock acquired	(9,951)				(9,951)
Net intercompany financing activity		21	54	(75)	
All other financing, net	959		(429)		530
Net cash provided by/(used in) financing activities	(17,034)	11	(15,023)	13,778	(18,268)
Effects of exchange rate changes on cash			532		532
Increase/(decrease) in cash and cash equivalents	$ 4,408	$	$ 3,497	$	$ 7,905

14. 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. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. 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. At the end of 2006, remaining shares available for award under the 2003 Incentive Program were 179,705 thousand.

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. All remaining stock options and SARs outstanding were granted prior to 2002.

Long-term incentive awards totaling 10,187 thousand, 11,071 thousand and 11,374 thousand shares of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2006, 2005 and 2004, respectively. These shares are issued to employees from treasury stock. The total compensation expense is recognized over the requisite service period. The units that are settled in cash are recorded as liabilities and their changes in fair value are 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 senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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The Corporation has purchased shares in the open market and through negotiated transactions to offset shares issued in conjunction with benefit plans and programs. Purchases may be discontinued at any time without prior notice.

In 2002, the Corporation began issuing restricted stock as share-based compensation in lieu of stock options. Compensation expense for these awards is based on the price of the stock at the date of grant and has been recognized in income over the requisite service period, which is the same method of accounting as under FAS 123R. Prior to 2002, the Corporation issued stock options as share-based compensation and since these awards vested prior to the effective date of FAS 123R, they continue to be accounted for by the method prescribed in APB 25, Accounting for Stock Issued to Employees. 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 the stock and the exercise price of the options) on the date of grant. Since these two prices were the same on the date of grant, no compensation expense has been recognized in income for these awards.

The following table summarizes information about restricted stock and restricted stock units, including those shares from former Mobil plans, for the year ended December 31, 2006.

Restricted Stock and Units Outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	
Issued and outstanding at January 1	29,530	$ 41.52
2005 award issued in 2006	11,064	$ 58.43
Vested	(4,298)	$ 36.23
Forfeited	(172)	$ 46.30
Issued and outstanding at December 31, 2006	36,124	$ 47.30

Grant Value of Restricted Stock and Units	**2006**	**2005**	**2004**
Grant price	$ 73.47	$ 58.43	$ 51.07
	(millions of dollars)		
Value at date of grant:			
Restricted stock and units settled in stock	$ 704	$ 611	$ 554
Units settled in cash	44	36	27
Total value	$ 748	$ 647	$ 581

As of December 31, 2006, there was $1,600 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.7 years. The compensation cost charged against income for the restricted stock and restricted units was $527 million, $387 million and $189 million for 2006, 2005 and 2004, respectively. The income tax benefit recognized in income related to this compensation expense was $72 million, $69 million and $58 million for the same periods, respectively. The fair value of shares and units vested in 2006, 2005 and 2004 was $310 million, $288 million and $10 million, respectively. Cash payments of $18 million and $15 million for vested restricted stock units settled in cash were made in 2006 and 2005, respectively. No cash payments were made in 2004.

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Changes that occurred in stock options in 2006 are summarized below (shares in thousands):

	2006		
Stock Options	**Shares**	**Avg. Exercise Price**	**Weighted Average Remaining Contractual Term**
Outstanding at January 1	147,774	$ 37.11	
Exercised	(37,016)	$ 31.85	
Forfeited	(271)	$ 37.80	
Outstanding at December 31	110,487	$ 38.86	3.4 Years
Exercisable at December 31	110,487	$ 38.86	3.4 Years

No compensation expense was recognized for stock options in 2006, 2005 and 2004, as all remaining outstanding stock options were granted prior to 2002 and are fully vested. Cash received from stock option exercises was $1,173 million, $941 million and $960 million for 2006, 2005 and 2004, respectively. The cash tax benefit realized for the options exercised was $416 million, $295 million and $302 million for 2006, 2005 and 2004, respectively. The aggregate intrinsic value of stock options exercised in 2006, 2005 and 2004 was $1,304 million, $954 million and $979 million, respectively. The intrinsic value for the balance of outstanding stock options at December 31, 2006, was $4,173 million.

15. 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. Management has regular litigation and tax reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. 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. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. 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. All the compensatory claims have been resolved and paid. All of the punitive damage claims were consolidated in the civil trial that began in 1994. The first judgment from the United States District Court for the District of Alaska in the amount of $5 billion was vacated by the United States Court of Appeals for the Ninth Circuit as being excessive under the Constitution. The second judgment in the amount of $4 billion was vacated by the Ninth Circuit panel without argument and sent back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm.* The most recent District Court judgment for punitive damages was for $4.5 billion plus interest and was entered in January 2004. The Corporation posted a $5.4 billion letter of credit. ExxonMobil and the plaintiffs appealed this decision to the Ninth Circuit, which ruled on December 22, 2006, that the award be reduced to $2.5 billion. On January 12, 2007, ExxonMobil petitioned the Ninth Circuit Court of Appeals for a rehearing en banc of its appeal. While it is reasonably possible that a liability for punitive damages may have been incurred from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

In December 2000, a jury in the 15th Judicial Circuit Court of Montgomery County, Alabama, returned a verdict against the Corporation in a dispute over royalties in the amount of $88 million in compensatory damages and $3.4 billion in punitive damages in the case of *Exxon Corporation v. State of Alabama, et al.* The verdict was upheld by the trial court in May 2001. In December 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and in November 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. In March 2004, the district court judge reduced the amount of punitive damages to $3.5 billion. ExxonMobil believes the judgment is not justified by the evidence, that any punitive damage award is not justified by either the facts or the law, and that the amount of the award is grossly excessive and unconstitutional. ExxonMobil has appealed the decision to the Alabama Supreme Court. The Alabama Supreme Court heard oral arguments on February 6, 2007. Management believes that the likelihood of the judgment 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. In May 2004, the Corporation posted a $4.5 billion supersedeas bond as required by Alabama law to stay execution of the judgment pending appeal. The Corporation has pledged to the issuer of the bond collateral consisting of cash and short-term, high-quality securities with an aggregate value of approximately $4.6 billion. This collateral is reported as restricted cash and cash equivalents on the Consolidated Balance Sheet. Under the terms of the pledge agreement, the Corporation is entitled to receive the income generated from the

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cash and securities and to make investment decisions, but is restricted from using the pledged cash and securities for any other purpose until such time the bond is canceled.

In 2001, a Louisiana state court jury awarded compensatory damages of $56 million and punitive damages of $1 billion to a landowner for damage caused by a third party that leased the property from the landowner. The third party provided pipe cleaning and storage services for the Corporation and other entities. The Louisiana Fourth Circuit Court of Appeals reduced the punitive damage award to $112 million in 2005. The Corporation appealed this decision to the Louisiana Supreme Court which, in March 2006, refused to hear the appeal. ExxonMobil has fully accrued and paid the compensatory and punitive damage awards. The Corporation appealed the punitive damage award to the U.S. Supreme Court, which on February 26, 2007, vacated the judgment and remanded the case to the Louisiana Fourth Circuit Court of Appeals for reconsideration in light of the recent U.S. Supreme Court decision in *Williams v. Phillip Morris USA*.

In *Allapattah v. Exxon,* a jury in the United States District Court for the Southern District of Florida determined in 2001 that a class of Exxon dealers between March 1983 and August 1994 had been overcharged for gasoline. In June 2003, the Eleventh Circuit Court of Appeals affirmed the judgment and in March 2004, denied a petition for a rehearing en banc. In October 2004, the U.S. Supreme Court granted review as to whether the class in the District Court judgment should include members that individually do not satisfy the $50,000 minimum amount-in-controversy requirement in federal court. In light of the Supreme Court s decision to grant review of only part of ExxonMobil s appeal, the Corporation took an after-tax charge of $550 million in the third quarter of 2004 reflecting the estimated liability, after considering potential set-offs and defenses for the claims under review by the Supreme Court. In June 2005, the Supreme Court granted the District Court the right to hear the claims of all class members and the Corporation took an after-tax charge of $200 million. The District Court has given final approval of a settlement of $1,075 million, pre-tax. This obligation has been fully accrued and was paid in the second quarter 2006.

Tax issues for 1989 to 1993 remain pending before the U.S. Tax 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

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2006, for $4,252 million, primarily relating to guarantees for notes, loans and performance under contracts. Included in this amount were guarantees by consolidated affiliates of $3,507 million, representing ExxonMobil s share of obligations of certain equity companies.

	Dec. 31, 2006		
	Equity Company Obligations	Other Third-Party Obligations	Total
		(millions of dollars)	
Total guarantees	$ 3,507	$ 745	$ 4,252

Additionally, the Corporation and its consolidated subsidiaries 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

	2007	2008-2011	2012 and Beyond	Total
		(millions of dollars)		
Unconditional purchase obligations *(1)*	$ 587	$ 1,797	$ 1,599	$ 3,983

(1) Undiscounted obligations of $3,983 million mainly pertain to pipeline throughput agreements and include $2,039 million of obligations to equity companies. The present value of these commitments, excluding imputed interest of $1,127 million, totaled $2,856 million.

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16. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2006	2005	2006	2005	2006	2005
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	6.00	5.75	4.70	4.50	6.00	5.75
Long-term rate of compensation increase	3.50	3.50	4.20	3.90	3.50	3.50
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	$ 11,181	$ 10,770	$ 19,310	$ 18,704	$ 5,370	$ 5,388
Service cost	335	330	428	382	76	70
Interest cost	632	611	911	834	308	301
Actuarial loss/(gain)	484	279	(38)	1,608	1,440	(17)
Benefits paid *(1) (2)*	(1,329)	(809)	(1,153)	(1,037)	(419)	(431)
Foreign exchange rate changes			1,424	(1,577)		15
Plan amendments, other	2		74	396	68	44
Benefit obligation at December 31	$ 11,305	$ 11,181	$ 20,956	$ 19,310	$ 6,843	$ 5,370
Accumulated benefit obligation at December 31	$ 9,811	$ 9,477	$ 18,883	$ 17,467	$	$

(1) Benefit payments for funded and unfunded plans.
(2) For 2006, other postretirement benefits paid are net of a $20 million Medicare subsidy receipt.

For U.S. plans, the discount rate is determined by constructing a portfolio of high-quality, noncallable bonds with cash flows that match estimated outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using bond portfolios with an average maturity approximating that of the liabilities or spot yield curves, both of which are constructed using high-quality, local-currency-denominated bonds.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 7.5 percent for 2007 that declines to 4.5 percent by 2014. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $55 million and the postretirement benefit obligation by $583 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $45 million and the postretirement benefit obligation by $483 million. At year-end 2005, the measurement of the accumulated postretirement benefit obligation assumed an initial health care cost trend rate of 4.5 percent that declined to 2.5 percent by 2011.

The Corporation offers a Medicare supplement plan to Medicare-eligible retirees that provides prescription drug benefits. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 provides 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. The Corporation believes that its Medicare supplement plan is at least actuarially equivalent to Medicare Part D.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2006	2005	2006	2005	2006	2005
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	$ 7,250	$ 7,299	$ 12,063	$ 10,673	$ 456	$ 444
Actual return on plan assets	1,207	626	1,669	1,871	66	30
Foreign exchange rate changes			891	(860)		
Company contribution	2,383		724	1,055	34	36
Benefits paid *(1)*	(1,088)	(675)	(825)	(714)	(55)	(54)
Other			(135)	38		
Fair value at December 31	$ 9,752	$ 7,250	$ 14,387	$ 12,063	$ 501	$ 456

(1) Benefit payments for funded plans.

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2006	2005	2006	2005	2006	2005
			(millions of dollars)			
Assets in excess of/(less than) benefit obligation						
Balance at December 31						
Funded plans	$ (254)	$ (2,588)	$ (1,479)	$ (2,490)	$ (528)	$ (491)
Unfunded plans	(1,299)	(1,343)	(5,090)	(4,757)	(5,814)	(4,423)
Total *(1)*	$ (1,553)	$ (3,931)	$ (6,569)	$ (7,247)	$ (6,342)	$ (4,914)

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

In 2006, the Corporation contributed $2,383 million to the U.S. funded pension plan, the maximum tax-deductible amount. As a result, year-end 2006 U.S. pension assets of $9,752 million were $1,061 million greater than the funded plan accumulated benefit obligation of $8,691 million.

The funding levels of all qualified plans are in compliance with standards set by applicable law or regulation. 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.

Effective December 31, 2006, Exxon Mobil Corporation implemented FASB Statement No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (FAS 158), which requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other nonowner changes in equity. In 2006, the amounts recorded in other nonowner changes in equity for net actuarial losses and prior service costs are required by FAS 158. For 2005, FASB Statement No. 87, Employers Accounting for Pensions, required an employer to recognize a liability in its statement of financial position that was at least equal to the unfunded accumulated benefit obligation for defined benefit pension plans.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2006	2005	2006	2005	2006	2005
			(millions of dollars)			
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	$ 36	$ 37	$ 196	$ 715	$	$

Current liabilities	(160)	(162)	(294)	(335)	(311)	(343)
Postretirement benefits reserves	(1,429)	(2,094)	(6,471)	(5,591)	(6,031)	(2,535)
Total recorded	$ (1,553)	$ (2,219)	$ (6,569)	$ (5,211)	$ (6,342)	$ (2,878)
Cumulative amounts recorded in other nonowner changes in equity consist of:						
Net actuarial loss/(gain)	$ 2,044	$ 779	$ 3,838	$ 2,924	$ 2,831	$
Prior service cost *(1)*	121		780		401	
Total recorded in other nonowner changes in equity, before tax	$ 2,165	$ 779	$ 4,618	$ 2,924	$ 3,232	$

(1) For 2005, unamortized prior service cost for plans requiring a minimum pension liability adjustment was recorded as an intangible asset under FAS 87 ($204 million for U.S. pension plans and $388 million for non-U.S. pension plans).

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	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2006	2005	2004	2006	2005	2004	2006	2005	2004
					(percent)				
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31									
Discount rate	5.75	5.75	6.00	4.50	4.90	5.20	5.75	5.75	6.00
Long-term rate of return on funded assets	9.00	9.00	9.00	7.70	7.70	7.70	9.00	9.00	9.00
Long-term rate of compensation increase	3.50	3.50	3.50	3.90	3.80	3.80	3.50	3.50	3.50
					(millions of dollars)				
Components of net periodic benefit cost									
Service cost	$ 335	$ 330	$ 308	$ 428	$ 382	$ 357	$ 76	$ 70	$ 62
Interest cost	632	611	611	911	834	812	308	301	295
Expected return on plan assets	(620)	(629)	(618)	(982)	(789)	(684)	(41)	(39)	(36)
Amortization of actuarial loss/(gain)	249	247	258	434	360	319	145	131	114
Amortization of prior service cost	24	27	28	79	64	59	73	73	77
Net pension enhancement and curtailment/settlement expense	157	123	177	47	10	3			
Net periodic benefit cost	$ 777	$ 709	$ 764	$ 917	$ 861	$ 866	$ 561	$ 536	$ 512
Changes in amounts recorded in other nonowner changes in equity									
Net actuarial loss/(gain)	$ 1,265	$ (196)	$ (135)	$ 914	$ (74)	$ 110	$ 2,831	$	$
Prior service cost	121			780			401		
Total recorded in other nonowner changes in equity	1,386	(196)	(135)	1,694	(74)	110	3,232		
Total recorded in net periodic benefit cost and other nonowner changes in equity, before tax	$ 2,163	$ 513	$ 629	$ 2,611	$ 787	$ 976	$ 3,793	$ 536	$ 512

Costs for defined contribution plans were $260 million, $251 million and $245 million in 2006, 2005 and 2004, respectively.

A summary of the change in other nonowner changes in equity is shown in the table below:

	Total Pension and Other Postretirement Benefits		
	2006	2005	2004
		(millions of dollars)	
(Charge)/credit to accumulated other nonowner changes in equity, before tax			
U.S. pension	$ (1,386)	$ 196	$ 135
Non-U.S. pension	(1,694)	74	(110)
Other postretirement benefits	(3,232)		

Total (charge)/credit to accumulated other nonowner changes in equity, before tax	(6,312)	270	25
(Charge)/credit to income tax (see note 18)	2,105	(90)	(49)
Charge/(credit) to equity of minority shareholders	38	61	(29)
(Charge)/credit to investment in equity companies	(68)		
(Charge)/credit to accumulated other nonowner changes in equity, after tax	$ (4,237)	$ 241	$ (53)

The impact of adopting FAS 158 on the Consolidated Balance Sheet is shown in the table below:

	Pre-FAS 158 With Minimum Pension Liability Adjustment	FAS 158 Adoption Adjustments	Post-FAS 158
		(millions of dollars)	
Intangible asset	$ 367	$ (367)	$
Postretirement benefits reserves/other assets	(6,438)	(7,261)	(13,699)*(1)*
Other nonowner changes in equity, before tax	(2,387)	(7,628)	(10,015)
Deferred tax asset	800	2,572	3,372
Equity of minority shareholders	78	138	216
Investment in equity companies		(68)	(68)
Other nonowner changes in equity, after tax	$ (1,509)	$ (4,986)	$ (6,495)

(1) Includes postretirement benefits reserves of $(13,931) million and other assets of $232 million.

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The data on the preceding pages conform 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 pension 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 asset allocation. The U.S. long-term expected rate of return of 9.0 percent used in 2006 compares to an actual rate of return for the U.S. pension fund over the past decade of 11 percent. The Corporation establishes the long-term expected rate of return for each plan 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.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2006	2005	2006	2005	2006	2005
	(percent)					
Funded benefit plan asset allocation						
Equity securities	75%	75%	69%	68%	75%	75%
Debt securities	25	25	27	28	25	25
Other			4	4		
Total	100%	100%	100%	100%	100%	100%

The Corporation 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 Corporation 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. Studies are periodically conducted to establish the preferred target asset allocation. The target asset allocation for equity securities of 75 percent for the U.S. benefit plans and 67 percent for non-U.S. plans reflects the long-term nature of the liability. The balance of the funds is largely targeted to debt securities.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2006	2005	2006	2005
	(millions of dollars)			
For funded pension plans with accumulated benefit obligations in excess of plan assets:				
Projected benefit obligation	$ 4	$ 9,816	$ 8,971	$ 11,352
Accumulated benefit obligation	3	8,356	8,322	10,480
Fair value of plan assets	2	7,198	7,265	8,876
For unfunded pension plans:				
Projected benefit obligation	1,299	1,343	5,090	4,757

Accumulated benefit obligation	1,120	1,098	4,502	4,211

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2007 amortization from other nonowner changes in shareholders equity:			
Net actuarial loss/(gain) *(1)*	$ 338	$ 325	$ 244
Prior service cost *(2)*	$ 23	$ 87	$ 75

(1) The Corporation amortizes the net balance of actuarial losses/(gains) as a component of net periodic benefit cost over the average remaining service period of active plan participants.

(2) The Corporation amortizes prior service cost on a straight-line basis as permitted under FAS 87 and FAS 106.

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	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
		(millions of dollars)		
Contributions expected in 2007	$	$ 550	$	$
Benefit payments expected in:				
2007	847	1,087	379	22
2008	873	1,089	396	23
2009	917	1,119	415	25
2010	953	1,115	434	26
2011	989	1,091	453	28
2012 - 2016	5,473	6,793	2,467	161

17. Disclosures about Segments and Related Information

The Upstream, Downstream and Chemical 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. The Chemical 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 after income tax include special items, and transfers are at estimated market prices. After-tax earnings in 2006 include a $410 million special gain in the corporate and financing segment from the recognition of tax benefits related to historical investments in non-U.S. assets. Special items included in 2005 after-tax earnings are a $1,620 million gain in Non-U.S. Upstream for the restructuring of a Dutch gas equity company, a $390 million gain in Non-U.S. Chemical relating to joint venture litigation, gains of $310 million and $150 million in Non-U.S. Downstream and Non-U.S. Chemical, respectively, for the Sinopec share sale and a charge of $200 million in U.S. Downstream relating to the Allapattah lawsuit provision. U.S. Downstream after-tax earnings in 2004 included a charge of $550 million relating to Allapattah.

Interest expense includes non-debt-related interest expense of $535 million, $369 million and $529 million in 2006, 2005 and 2004, respectively. The increase of $166 million in 2006 reflects higher tax-related interest. The decrease of $160 million in 2005 reflects a lower interest component for the Allapattah lawsuit provision.

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities.

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	Upstream		Downstream		Chemical			
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Corporate and Financing	Corporate Total
				(millions of dollars)				
As of December 31, 2006								
Earnings after income tax	$ 5,168	$ 21,062	$ 4,250	$ 4,204	$ 1,360	$ 3,022	$ 434	$ 39,500
Earnings of equity companies included above	1,323	4,236	227	279	84	1,180	(344)	6,985
Sales and other operating revenue *(1)*	6,054	26,821	93,437	205,020	13,273	20,825	37	365,467
Intersegment revenue	7,118	39,963	12,603	46,675	7,849	6,997	292	
Depreciation and depletion expense	1,263	6,482	632	1,605	427	473	534	11,416
Interest revenue							1,571	1,571
Interest expense	103	264	1	34			252	654
Income taxes	3,130	20,932	2,318	1,174	654	700	(1,006)	27,902
Additions to property, plant and equipment	1,942	9,735	718	1,757	257	384	669	15,462
Investments in equity companies	1,665	8,065	451	949	245	2,261	(57)	13,579
Total assets	21,119	75,090	16,740	47,694	7,652	11,885	38,835	219,015
As of December 31, 2005								
Earnings after income tax	$ 6,200	$ 18,149	$ 3,911	$ 4,081	$ 1,186	$ 2,757	$ (154)	$ 36,130
Earnings of equity companies included above	1,106	5,084	165	471	53	954	(250)	7,583
Sales and other operating revenue *(1)*	6,730	23,324	91,954	205,726	11,842	19,344	35	358,955
Intersegment revenue	7,230	31,371	9,817	40,255	6,521	5,413	290	
Depreciation and depletion expense	1,293	5,407	615	1,611	416	410	501	10,253
Interest revenue							946	946
Interest expense	30	32	230	34	4	4	162	496
Income taxes	3,516	15,968	2,139	1,362	447	794	(924)	23,302
Additions to property, plant and equipment	1,763	8,796	662	1,618	218	268	514	13,839
Investments in equity companies	1,470	6,735	420	937	275	2,282	(3)	12,116
Total assets	20,827	66,239	16,110	47,691	7,794	11,702	37,972	208,335
As of December 31, 2004								
Earnings after income tax	$ 4,948	$ 11,727	$ 2,186	$ 3,520	$ 1,020	$ 2,408	$ (479)	$ 25,330
Earnings of equity companies included above	904	2,709	138	466	31	914	(201)	4,961
Sales and other operating revenue *(1)*	5,990	17,043	71,645	168,768	10,729	17,052	25	291,252
Intersegment revenue	6,547	21,800	8,047	26,577	4,937	4,278	306	
Depreciation and depletion expense	1,453	4,758	618	1,646	408	400	484	9,767
Interest revenue							361	361
Interest expense	25	27	431	33	2	1	119	638
Income taxes	2,733	10,168	1,371	1,073	450	731	(615)	15,911
Additions to property, plant and equipment	1,465	7,358	668	1,472	247	201	575	11,986
Investments in equity companies	1,347	6,595	401	1,047	276	2,079	(3)	11,742
Total assets	19,330	62,204	14,685	49,688	8,102	13,052	28,195	195,256

Geographic Sales and other operating revenue *(1)*	2006	2005	2004

	(millions of dollars)		
United States	$ 112,787	$ 110,553	$ 88,382
Non-U.S.	252,680	248,402	202,870
Total	$ 365,467	$ 358,955	$ 291,252
Significant non-U.S. revenue sources include:			
Japan	$ 27,368	$ 28,963	$ 25,485
Canada	25,281	28,842	21,689
United Kingdom	24,646	24,805	22,549
Germany	19,458	21,653	17,649
Belgium	16,271	11,281	7,204
Italy	15,332	17,160	15,096
France	13,537	14,412	12,231

(1) Sales and other operating revenue includes sales-based taxes of $30,381 million for 2006, $30,742 million for 2005 and $27,263 million for 2004. Includes amounts for purchases/sales contracts with the same counterparty for 2004 and 2005. Associated costs were included in Crude oil and product purchases. Effective January 1, 2006, these purchases/sales were recorded on a net basis with no resulting impact on net income. See note 1, Summary of Accounting Policies.

Long-lived assets	**2006**	**2005**	**2004**
	(millions of dollars)		
United States	$ 33,233	$ 33,117	$ 33,569
Non-U.S.	80,454	73,893	75,070
Total	$ 113,687	$ 107,010	$ 108,639
Significant non-U.S. long-lived assets include:			
Canada	$ 12,323	$ 12,273	$ 11,806
United Kingdom	9,128	7,757	9,545
Nigeria	7,350	6,409	4,923
Norway	6,977	6,472	7,561
Angola	4,271	3,803	3,544
Japan	4,008	4,016	4,784
Australia	2,966	2,717	2,866
Singapore	2,964	2,968	3,089

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18. Income, Sales-Based and Other Taxes

	2006			2005			2004		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
				(millions of dollars)					
Income taxes									
Federal and non-U.S.									
Current	$ 2,851	$ 22,666	$ 25,517	$ 5,462	$ 17,052	$ 22,514	$ 4,410	$ 12,030	$ 16,440
Deferred net	1,194	165	1,359	(584)	362	(222)	(1,113)	122	(991)
U.S. tax on non-U.S. operations	239		239	208		208	56		56
Total federal and non-U.S.	4,284	22,831	27,115	5,086	17,414	22,500	3,353	12,152	15,505
State	787		787	802		802	406		406
Total income taxes	5,071	22,831	27,902	5,888	17,414	23,302	3,759	12,152	15,911
Sales-based taxes	7,100	23,281	30,381	7,072	23,670	30,742	6,833	20,430	27,263
All other taxes and duties									
Other taxes and duties	392	38,811	39,203	51	41,503	41,554	26	40,928	40,954
Included in production and manufacturing expenses	976	1,431	2,407	1,182	1,075	2,257	982	951	1,933
Included in SG&A expenses	211	572	783	202	558	760	215	503	718
Total other taxes and duties	1,579	40,814	42,393	1,435	43,136	44,571	1,223	42,382	43,605
Total	$ 13,750	$ 86,926	$ 100,676	$ 14,395	$ 84,220	$ 98,615	$ 11,815	$ 74,964	$ 86,779

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 credits for the effect of changes in tax laws and rates of $169 million in 2006, $199 million in 2005 and $318 million in 2004.

Income taxes (charged)/credited directly to shareholders equity were:

	2006	2005	2004
		(millions of dollars)	
Cumulative foreign exchange translation adjustment	$ (36)	$ 158	$ (180)
Postretirement benefits reserves adjustment	3,372		
Minimum pension liability adjustment	(1,267)	(90)	(49)
Gains and losses on stock investments		236	53
Other components of shareholders equity	169	224	183

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2006, 2005 and 2004, is as follows:

	2006	2005	2004
		(millions of dollars)	
Income before income taxes			
United States	$ 15,507	$ 16,900	$ 11,473
Non-U.S.	51,895	42,532	29,768
Total	$ 67,402	$ 59,432	$ 41,241
Theoretical tax	$ 23,591	$ 20,801	$ 14,434
Effect of equity method of accounting	(2,445)	(2,654)	(1,736)
Non-U.S. taxes in excess of theoretical U.S. tax	6,541	4,719	3,093
U.S. tax on non-U.S. operations	239	208	56
State taxes, net of federal tax benefit	512	522	264
Other U.S.	(536)	(294)	(200)
Total income tax expense	$ 27,902	$ 23,302	$ 15,911
Effective tax rate calculation			
Income taxes	$ 27,902	$ 23,302	$ 15,911
ExxonMobil share of equity company income taxes	1,920	2,226	1,180
Total income taxes	29,822	25,528	17,091
Income from continuing operations	39,500	36,130	25,330
Total income before taxes	$ 69,322	$ 61,658	$ 42,421
Effective income tax rate	43%	41%	40%

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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:	2006	2005
	(millions of dollars)	
Depreciation	$ 17,518	$ 17,000
Intangible development costs	4,742	4,809
Capitalized interest	2,499	2,311
Other liabilities	3,240	2,457
Total deferred tax liabilities	$ 27,999	$ 26,577
Pension and other postretirement benefits	$ (4,135)	$ (2,654)
Tax loss carryforwards	(2,002)	(1,996)
Other assets	(4,894)	(5,091)
Total deferred tax assets	$ (11,031)	$ (9,741)
Asset valuation allowances	657	566
Net deferred tax liabilities	$ 17,625	$ 17,402

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	2006	2005
	(millions of dollars)	
Prepaid taxes and expenses	$ (1,636)	$ (2,081)
Other assets, including intangibles, net	(1,656)	(1,540)
Accounts payable and accrued liabilities	66	145
Deferred income tax liabilities	20,851	20,878
Net deferred tax liabilities	$ 17,625	$ 17,402

The Corporation had $47 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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SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

The results of operations for producing activities shown below are presented in accordance with Statement of Financial Accounting Standards No. 69. As such, they do not include earnings from other activities that ExxonMobil includes in the Upstream function such as oil and gas transportation operations, oil sands operations, LNG liquefaction and transportation operations, coal and power operations, technical services agreements, other nonoperating activities and adjustments for minority interests. These excluded amounts for both consolidated and equity companies totaled $2,431 million in 2006, $3,546 million in 2005 and $1,340 million in 2004.

Results of Operations	United States	Canada	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of dollars)				
2006 Revenue								
Sales to third parties	$ 4,027	$ 3,694	$ 9,382	$ 1,145	$ 4,393	$ 533	$ 696	$ 23,870
Transfers	6,250	2,531	8,607	16,108	4,900	580	107	39,083
	$ 10,277	$ 6,225	$ 17,989	$ 17,253	$ 9,293	$ 1,113	$ 803	$ 62,953
Production costs excluding taxes	1,916	1,318	2,290	965	824	118	92	7,523
Exploration expenses	245	75	161	330	157	116	97	1,181
Depreciation and depletion	1,155	858	2,166	2,096	674	305	165	7,419
Taxes other than income	802	60	846	1,612	2,652	1	79	6,052
Related income tax	2,711	951	8,032	6,878	2,820	217	192	21,801
Results of producing activities for consolidated subsidiaries	$ 3,448	$ 2,963	$ 4,494	$ 5,372	$ 2,166	$ 356	$ 178	$ 18,977
Proportional interest in results of producing activities of equity companies	$ 1,236	$	$ 1,164	$	$ 1,555	$ 867	$	$ 4,822
2005 Revenue								
Sales to third parties	$ 4,842	$ 3,216	$ 8,383	$ 40	$ 2,357	$ 357	$ 512	$ 19,707
Transfers	6,277	3,400	7,040	12,293	3,143	279	182	32,614
	$ 11,119	$ 6,616	$ 15,423	$ 12,333	$ 5,500	$ 636	$ 694	$ 52,321
Production costs excluding taxes	1,367	1,265	2,174	840	567	123	105	6,441
Exploration expenses	158	36	64	310	122	164	101	955
Depreciation and depletion	1,181	983	2,133	1,319	666	137	58	6,477
Taxes other than income	738	53	690	1,158	839	2	3	3,483
Related income tax	3,138	1,482	6,572	5,143	1,313	111	159	17,918
Results of producing activities for consolidated subsidiaries	$ 4,537	$ 2,797	$ 3,790	$ 3,563	$ 1,993	$ 99	$ 268	$ 17,047
Proportional interest in results of producing activities of equity companies	$ 1,043	$	$ 1,003	$	$ 1,009	$ 701	$	$ 3,756
2004 Revenue								
Sales to third parties	$ 4,203	$ 2,460	$ 6,714	$ 29	$ 2,291	$ 74	$ 480	$ 16,251
Transfers	5,555	2,680	5,347	7,272	2,770	157	22	23,803

	$ 9,758	$ 5,140	$ 12,061	$ 7,301	$ 5,061	$ 231	$ 502	$ 40,054
Production costs excluding taxes	1,442	1,085	1,932	719	643	102	82	6,005
Exploration expenses	193	92	112	321	104	188	76	1,086
Depreciation and depletion	1,335	969	2,082	839	702	35	60	6,022
Taxes other than income	550	49	582	722	634		3	2,540
Related income tax	2,546	1,015	4,417	2,789	1,103	2	97	11,969
Results of producing activities for consolidated subsidiaries	$ 3,692	$ 1,930	$ 2,936	$ 1,911	$ 1,875	$ (96)	$ 184	$ 12,432
Proportional interest in results of producing activities of equity companies	$ 810	$	$ 993	$	$ 635	$ 465	$	$ 2,903

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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 proved reserves table of this report. The volumes for natural gas used for this calculation are the production volumes of natural gas available for sale and thus are different than those shown in the proved reserves table of this report due to volumes consumed or flared. The volumes of natural gas were converted to oil-equivalent barrels based on a conversion factor of six thousand cubic feet per barrel.

Average sales prices and production costs per unit of production consolidated subsidiaries	**United States**	**Canada**	**Europe**	**Africa**	**Asia Pacific/ Middle East**	**Russia/ Caspian**	**Other**	**Total**
During 2006								
Average sales prices								
Crude oil and NGL, per barrel	$ 55.13	$ 46.50	$ 59.90	$ 61.26	$ 62.02	$ 57.38	$ 55.79	$ 58.34
Natural gas, per thousand cubic feet	6.22	6.26	7.48		3.87	2.31	1.30	6.08
Average production costs, per barrel *(1)*	8.78	9.12	6.64	3.39	3.90	5.45	4.53	6.04
During 2005								
Average sales prices								
Crude oil and NGL, per barrel	$ 46.11	$ 38.38	$ 50.32	$ 51.21	$ 52.89	$ 51.65	$ 40.67	$ 48.23
Natural gas, per thousand cubic feet	7.30	7.43	5.64		4.16	1.35	1.20	5.96
Average production costs, per barrel *(1)*	5.56	7.76	5.95	3.46	3.85	9.49	4.54	5.36
During 2004								
Average sales prices								
Crude oil and NGL, per barrel	$ 34.84	$ 30.26	$ 35.71	$ 35.04	$ 39.04	$ 34.99	$ 26.89	$ 34.76
Natural gas, per thousand cubic feet	5.53	5.23	4.20		3.41		1.13	4.48
Average production costs, per barrel *(1)*	5.05	6.47	4.95	3.44	3.72	16.62	3.23	4.78

(1) 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

The amounts shown for net capitalized costs of consolidated subsidiaries are $5,463 million less at year-end 2006 and $5,541 million less at year-end 2005 than the amounts reported as investments in property, plant and equipment for the Upstream in note 8. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to the oil sands and LNG operations, all as required by Statement of Financial Accounting Standards No. 19.

Capitalized Costs		United States	Canada	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
					(millions of dollars)				
As of December 31, 2006									
Property (acreage) costs	Proved	$ 3,260	$ 3,323	$ 277	$ 200	$ 1,164	$ 512	$ 209	$ 8,945
	Unproved	574	229	31	523	1,070	99	200	2,726
Total property costs		$ 3,834	$ 3,552	$ 308	$ 723	$ 2,234	$ 611	$ 409	$ 11,671
Producing assets		34,852	11,695	44,719	16,748	16,295	2,324	1,105	127,738
Support facilities		740	201	581	442	1,158	308	56	3,486
Incomplete construction		2,273	831	1,439	3,533	1,537	2,605	62	12,280
Total capitalized costs		$ 41,699	$ 16,279	$ 47,047	$ 21,446	$ 21,224	$ 5,848	$ 1,632	$ 155,175
Accumulated depreciation and depletion		26,696	10,189	33,302	7,166	13,649	635	591	92,228
Net capitalized costs for consolidated subsidiaries		$ 15,003	$ 6,090	$ 13,745	$ 14,280	$ 7,575	$ 5,213	$ 1,041	$ 62,947
Proportional interest of net capitalized costs of equity companies		$ 1,527	$	$ 1,437	$	$ 1,238	$ 3,033	$	$ 7,235
As of December 31, 2005									
Property (acreage) costs	Proved	$ 3,407	$ 3,336	$ 210	$ 184	$ 954	$ 460	$ 209	$ 8,760
	Unproved	587	266	29	544	858	99	227	2,610
Total property costs		$ 3,994	$ 3,602	$ 239	$ 728	$ 1,812	$ 559	$ 436	$ 11,370
Producing assets		34,306	11,261	39,355	11,818	15,024	857	1,006	113,627
Support facilities		620	199	478	410	1,158	217	51	3,133
Incomplete construction		1,862	789	1,073	4,903	751	3,109	154	12,641
Total capitalized costs		$ 40,782	$ 15,851	$ 41,145	$ 17,859	$ 18,745	$ 4,742	$ 1,647	$ 140,771
Accumulated depreciation and depletion		26,071	9,573	28,899	5,115	13,070	330	437	83,495
Net capitalized costs for consolidated subsidiaries		$ 14,711	$ 6,278	$ 12,246	$ 12,744	$ 5,675	$ 4,412	$ 1,210	$ 57,276
Proportional interest of net capitalized costs of equity companies		$ 1,386	$	$ 1,310	$	$ 1,043	$ 2,746	$	$ 6,485

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

Oil and Gas Exploration and Production Costs *(continued)*

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 consolidated costs incurred in 2006 were $13,013 million, up $2,229 million from 2005, due primarily to higher development costs. 2005 costs were $10,784 million, up $1,767 million from 2004, due primarily to higher development and property acquisition costs.

Costs incurred in property acquisitions, exploration and development activities		**United States**	**Canada**	**Europe**	**Africa**	**Asia Pacific/ Middle East**	**Russia/ Caspian**	**Other**	**Total**
					(millions of dollars)				
During 2006									
Property acquisition costs	Proved	$ 11	$	$ 6	$	$ 206	$ 11	$	$ 234
	Unproved	43		5	16	199			263
Exploration costs		380	125	178	518	219	126	100	1,646
Development costs		1,555	796	2,443	3,433	1,475	1,114	54	10,870
Total costs incurred for consolidated subsidiaries		$ 1,989	$ 921	$ 2,632	$ 3,967	$ 2,099	$ 1,251	$ 154	$ 13,013
Proportional interest of costs incurred of equity companies		$ 285	$	$ 241	$	$ 243	$ 351	$	$ 1,120
During 2005									
Property acquisition costs	Proved	$	$	$	$	$	$ 174	$	$ 174
	Unproved	11	6		53	41	156	12	279
Exploration costs		286	62	133	507	171	159	59	1,377
Development costs		1,426	624	1,302	3,189	541	1,774	98	8,954
Total costs incurred for consolidated subsidiaries		$ 1,723	$ 692	$ 1,435	$ 3,749	$ 753	$ 2,263	$ 169	$ 10,784
Proportional interest of costs incurred of equity companies		$ 269	$	$ 210	$	$ 319	$ 384	$	$ 1,182
During 2004									
Property acquisition costs	Proved	$	$	$	$ 68	$	$ 25	$	$ 93
	Unproved	14	1		24	2			41
Exploration costs		232	68	123	382	110	189	86	1,190
Development costs		1,427	694	1,232	2,788	494	985	73	7,693
Total costs incurred for consolidated subsidiaries		$ 1,673	$ 763	$ 1,355	$ 3,262	$ 606	$ 1,199	$ 159	$ 9,017
Proportional interest of costs incurred of equity companies		$ 155	$	$ 169	$	$ 205	$ 451	$	$ 980

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Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2004, 2005 and 2006.

The definitions used are in accordance with the Securities and Exchange Commission s Rule 4-10 (a) of Regulation S-X, paragraphs (2) through (2)iii, (3) and (4).

Proved oil and gas 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. 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.

Beginning in 2004, the year-end reserves volumes as well as the reserves change categories shown in the following tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. Regulations preclude the Corporation from showing in this document the reserves that are calculated in a manner that is consistent with the basis that the Corporation uses to make its investment decisions. The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The Corporation believes that this approach is inconsistent with the long-term nature of the upstream business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the Corporation and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in year-end prices and costs that are used in the determination of reserves. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

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.

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, the Corporation does not view equity company reserves any differently than those from consolidated companies.

Reserves reported under production sharing and other nonconcessionary 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 (consolidated subsidiaries plus equity companies) at year-end 2006 that were associated with production sharing contract arrangements was 18 percent of liquids, 13 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).

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods. Undeveloped reserves are those volumes that 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 in the Operating Summary due to volumes consumed or flared and inventory changes.

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

Crude Oil and Natural Gas Liquids	United States	Canada *(1)*	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2004	2,792	1,194	1,184	2,742	615	850	512	9,889
Revisions	54	(460)	37	(243)	(5)	(120)	(14)	(751)
Purchases				10				10
Sales	(113)	(3)			(16)			(132)
Improved recovery	5							5
Extensions and discoveries	16	4	3	144	2			169
Production	(161)	(108)	(210)	(209)	(81)	(6)	(20)	(795)
December 31, 2004	2,593	627	1,014	2,444	515	724	478	8,395
Revisions	(256)	338	17	(8)	78	(27)	(2)	140
Purchases						93		93
Sales	(96)	(42)	(1)		(11)	(70)	(7)	(227)
Improved recovery	2		3					5
Extensions and discoveries	6	16	47	120				189
Production	(136)	(107)	(197)	(244)	(67)	(13)	(18)	(782)
December 31, 2005	2,113	832	883	2,312	515	707	451	7,813
Revisions	(99)	250	50	24	19	105	(3)	346
Purchases	4		8		734			746
Sales	(41)	(27)	(18)					(86)
Improved recovery	21							21
Extensions and discoveries	2		13	38	133			186
Production	(116)	(93)	(188)	(285)	(114)	(21)	(15)	(832)
December 31, 2006	1,884	962	748	2,089	1,287	791	433	8,194
Proportional interest in proved reserves of equity companies								
End of year 2004	402		17		1,169	911		2,499
End of year 2005	413		11		1,381	873		2,678
End of year 2006	391		12		1,412	841		2,656
Proved developed reserves, included above, as of December 31, 2004								
Consolidated subsidiaries	2,204	561	763	1,117	403	34	129	5,211
Equity companies	347		15		642	600		1,604
Proved developed reserves, included above, as of December 31, 2005								
Consolidated subsidiaries	1,680	607	656	1,218	464	55	227	4,907
Equity companies	326		9		725	574		1,634

Proved developed reserves, included above, as of December 31, 2006								
Consolidated subsidiaries	1,466	692	557	1,279	1,090	108	210	5,402
Equity companies	311		11		630	544		1,496

(1) Includes total proved reserves attributable to Imperial Oil Limited of 347 million barrels in 2004, 634 million barrels in 2005 and 812 million barrels in 2006, as well as proved developed reserves of 343 million barrels in 2004, 449 million barrels in 2005 and 572 million barrels in 2006, in which there is a 30.4 percent minority interest.

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Oil and Gas Reserves *(continued)*

Natural Gas	United States	Canada *(1)*	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
					(billions of cubic feet)			
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2004	11,272	2,341	10,146	583	7,939	469	645	33,395
Revisions	1,922	(77)	77	165	(659)	46	164	1,638
Purchases				9				9
Sales	(142)	(18)	(16)		(301)			(477)
Improved recovery	2		31					33
Extensions and discoveries	121	36	39	39	45			280
Production	(846)	(399)	(1,092)	(25)	(633)		(40)	(3,035)
December 31, 2004	12,329	1,883	9,185	771	6,391	515	769	31,843
Revisions	1,943	195	242	35	1,402	(18)	(112)	3,687
Purchases						53		53
Sales	(105)	(23)	(73)			(26)	(2)	(229)
Improved recovery								
Extensions and discoveries	289	26	116	57	32	300		820
Production	(764)	(376)	(1,072)	(22)	(546)	(3)	(36)	(2,819)
December 31, 2005	13,692	1,705	8,398	841	7,279	821	619	33,355
Revisions	(1,179)	190	(457)	170	414	(20)	(117)	(999)
Purchases	19		38					57
Sales	(57)	(44)	(3)					(104)
Improved recovery	12							12
Extensions and discoveries	268	10	117	1	2,534			2,930
Production	(706)	(344)	(1,004)	(26)	(644)	(12)	(35)	(2,771)
December 31, 2006	12,049	1,517	7,089	986	9,583	789	467	32,480
Proportional interest in proved reserves of equity companies								
End of year 2004	140		13,557		13,455	1,367		28,519
End of year 2005	136		13,024		19,119	1,273		33,552
End of year 2006	131		12,551		21,184	1,214		35,080

(1) Includes total proved reserves attributable to Imperial Oil Limited of 791 billion cubic feet in 2004, 747 billion cubic feet in 2005 and 710 billion cubic feet in 2006, in which there is a 30.4 percent minority interest.

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

Natural Gas ***(continued)***	**United States**	**Canada** ***(1)***	**Europe**	**Africa**	**Asia Pacific/ Middle East**	**Russia/ Caspian**	**Other**	**Total**
				(billions of cubic feet)				
Proved developed reserves, included above, as of December 31, 2004								
Consolidated subsidiaries	9,134	1,647	7,076	279	4,440	4	279	22,859
Equity companies	120		9,805		4,578	837		15,340
Proved developed reserves, included above, as of December 31, 2005								
Consolidated subsidiaries	10,386	1,527	6,332	376	6,067	227	313	25,228
Equity companies	113		10,226		7,276	835		18,450
Proved developed reserves, included above, as of December 31, 2006								
Consolidated subsidiaries	9,280	1,374	5,346	823	5,882	447	254	23,406
Equity companies	109		9,985		7,906	811		18,811

(1) Includes proved developed reserves attributable to Imperial Oil Limited of 704 billion cubic feet in 2004, 643 billion cubic feet in 2005 and 608 billion cubic feet in 2006, in which there is a 30.4 percent minority interest.

INFORMATION ON CANADIAN OIL SANDS PROVEN RESERVES NOT INCLUDED ABOVE

In addition to conventional liquids and natural gas proved reserves, ExxonMobil has significant interests in proven oil 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 oil sands reserves are not considered in the standardized measure of discounted future cash flows for conventional oil and gas reserves, which is on the following page.

Oil Sands Reserves	**Canada** ***(1)***
	(millions of barrels)
At December 31, 2004	757
At December 31, 2005	738
At December 31, 2006	718

(1) Oil sands proven reserves are attributable to Imperial Oil Limited, in which there is a 30.4 percent minority interest.

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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.

Standardized Measure of Discounted Future Cash Flows	United States	Canada *(1)*	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of dollars)				
Consolidated subsidiaries								
As of December 31, 2004								
Future cash inflows from sales of oil and gas	$ 141,261	$ 25,008	$ 79,698	$ 87,687	$ 31,795	$ 25,203	$ 11,708	$ 402,360
Future production costs	30,096	5,686	17,847	17,929	9,499	3,465	2,035	86,557
Future development costs	6,181	2,743	7,670	7,822	2,798	4,273	593	32,080
Future income tax expenses	42,928	5,662	28,883	33,945	7,466	4,203	2,944	126,031
Future net cash flows	$ 62,056	$ 10,917	$ 25,298	$ 27,991	$ 12,032	$ 13,262	$ 6,136	$ 157,692
Effect of discounting net cash flows at 10%	36,078	3,598	8,485	11,287	4,459	8,797	3,904	76,608
Discounted future net cash flows	$ 25,978	$ 7,319	$ 16,813	$ 16,704	$ 7,573	$ 4,465	$ 2,232	$ 81,084
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 4,079	$	$ 9,612	$	$ 11,137	$ 4,784	$	$ 29,612
Consolidated subsidiaries								
As of December 31, 2005								
Future cash inflows from sales of oil and gas	$ 200,119	$ 37,309	$ 107,127	$ 127,584	$ 44,411	$ 35,757	$ 17,644	$ 569,951
Future production costs	34,100	12,343	19,958	21,856	12,515	5,324	2,117	108,213
Future development costs	8,935	2,782	8,552	12,464	2,651	4,000	780	40,164
Future income tax expenses	67,581	7,606	47,999	51,610	13,151	6,608	4,737	199,292
Future net cash flows	$ 89,503	$ 14,578	$ 30,618	$ 41,654	$ 16,094	$ 19,825	$ 10,010	$ 222,282
Effect of discounting net cash flows at 10%	53,919	4,136	9,988	15,337	6,800	12,379	6,505	109,064
Discounted future net cash flows	$ 35,584	$ 10,442	$ 20,630	$ 26,317	$ 9,294	$ 7,446	$ 3,505	$ 113,218
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 7,000	$	$ 11,043	$	$ 25,311	$ 7,735	$	$ 51,089
Consolidated subsidiaries								
As of December 31, 2006								

Future cash inflows from sales of oil and gas	$ 139,843	$ 43,819	$ 83,854	$ 117,068	$ 100,751	$ 42,264	$ 17,368	$ 544,967
Future production costs	39,829	16,184	19,134	22,316	36,008	3,597	4,455	141,523
Future development costs	11,134	3,334	10,245	10,429	6,098	5,307	689	47,236
Future income tax expenses	42,665	7,192	34,050	48,235	35,200	8,156	5,759	181,257
Future net cash flows	$ 46,215	$ 17,109	$ 20,425	$ 36,088	$ 23,445	$ 25,204	$ 6,465	$ 174,951
Effect of discounting net cash flows at 10%	28,428	7,263	6,464	12,069	12,777	16,932	4,166	88,099
Discounted future net cash flows	$ 17,787	$ 9,846	$ 13,961	$ 24,019	$ 10,668	$ 8,272	$ 2,299	$ 86,852
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 6,337	$	$ 7,952	$	$ 20,617	$ 8,490	$	$ 43,396

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $2,773 million in 2004, $3,723 million in 2005 and $5,505 million in 2006, in which there is a 30.4 percent minority interest.

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

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

Consolidated Subsidiaries	2006	2005	2004
		(millions of dollars)	
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	$ 14,316	$ 4,619	$ 588
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	(49,732)	(42,606)	(31,726)
Development costs incurred during the year	9,465	8,617	7,660
Net change in prices, lifting and development costs	(35,342)	85,049	21,267
Revisions of previous reserves estimates	9,438	9,050	(766)
Accretion of discount	17,368	9,021	10,645
Net change in income taxes	8,121	(41,616)	(3,521)
Total change in the standardized measure during the year	$ (26,366)	$ 32,134	$ 4,147

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OPERATING SUMMARY (unaudited)

	2006	2005	2004	2003	2002
			(thousands of barrels daily)		
Production of crude oil and natural gas liquids					
Net production					
United States	414	477	557	610	681
Canada	312	346	355	363	349
Europe	520	546	583	579	592
Africa	781	666	572	442	349
Asia Pacific/Middle East	485	332	360	386	387
Russia/Caspian	127	107	91	88	91
Other Non-U.S.	42	49	53	48	47
Worldwide	2,681	2,523	2,571	2,516	2,496
			(millions of cubic feet daily)		
Natural gas production available for sale					
Net production					
United States	1,625	1,739	1,947	2,246	2,375
Canada	851	918	972	943	1,024
Europe	4,086	4,315	4,614	4,498	4,463
Asia Pacific/Middle East	2,596	2,114	2,161	2,258	2,427
Russia/Caspian	92	77	73	73	77
Other Non-U.S.	84	88	97	101	86
Worldwide	9,334	9,251	9,864	10,119	10,452
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	4,237	4,065	4,215	4,203	4,238
			(thousands of barrels daily)		
Refinery throughput					
United States	1,760	1,794	1,850	1,806	1,834
Canada	442	466	468	450	447
Europe	1,672	1,672	1,663	1,566	1,539
Asia Pacific	1,434	1,490	1,423	1,390	1,379
Other Non-U.S.	295	301	309	298	244
Worldwide	5,603	5,723	5,713	5,510	5,443
Petroleum product sales *(2)*					
United States	2,729	2,822	2,872	2,729	2,731
Canada	473	498	615	602	593
Europe	1,813	1,824	2,139	2,061	2,042
Asia Pacific and other Eastern Hemisphere	1,763	1,902	2,080	2,075	1,889
Latin America	469	473	504	490	502
Purchases/sales with same counterparty included above			(699)	(687)	(682)

Worldwide	7,247	7,519	7,511	7,270	7,075
Gasoline, naphthas	2,866	2,957	3,301	3,238	3,176
Heating oils, kerosene, diesel oils	2,191	2,230	2,517	2,432	2,292
Aviation fuels	651	676	698	662	691
Heavy fuels	682	689	659	638	604
Specialty petroleum products	857	967	1,035	987	994
Purchases/sales with same counterparty included above			(699)	(687)	(682)
Worldwide	7,247	7,519	7,511	7,270	7,075
			(thousands of metric tons)		
Chemical prime product sales					
United States	10,703	10,369	11,521	10,740	11,386
Non-U.S.	16,647	16,408	16,267	15,827	15,220
Worldwide	27,350	26,777	27,788	26,567	26,606

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.
(2) 2006 and 2005 petroleum product sales data are reported net of purchases/sales contracts with the same counterparty.

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SIGNATURES

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

EXXON MOBIL CORPORATION

By: /s/ REX W. TILLERSON

(Rex W. Tillerson,

Chairman of the Board)

Dated February 28, 2007

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints William M. Colton, Richard E. Gutman and David S. Rosenthal, 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/ REX W. TILLERSON	Chairman of the Board	February 28, 2007
(Rex W. Tillerson)	(Principal Executive Officer)	

/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director	February 28, 2007
/s/ WILLIAM W. GEORGE (William W. George)	Director	February 28, 2007

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/s/ JAMES R. HOUGHTON (James R. Houghton)	Director	February 28, 2007
/s/ WILLIAM R. HOWELL (William R. Howell)	Director	February 28, 2007
/s/ REATHA CLARK KING (Reatha Clark King)	Director	February 28, 2007
/s/ PHILIP E. LIPPINCOTT (Philip E. Lippincott)	Director	February 28, 2007
/s/ HENRY A. MCKINNELL, JR. (Henry A. McKinnell, Jr.)	Director	February 28, 2007
/s/ MARILYN CARLSON NELSON (Marilyn Carlson Nelson)	Director	February 28, 2007
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director	February 28, 2007
/s/ WALTER V. SHIPLEY (Walter V. Shipley)	Director	February 28, 2007
/s/ J. STEPHEN SIMON (J. Stephen Simon)	Director	February 28, 2007
/s/ DONALD D. HUMPHREYS (Donald D. Humphreys)	Treasurer (Principal Financial Officer)	February 28, 2007

/s/ PATRICK T. MULVA	Controller (Principal Accounting Officer)	February 28, 2007
(Patrick T. Mulva)		

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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, 2006).
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).	2003 Incentive Program (incorporated by reference to Appendix B to the Proxy Statement of Exxon Mobil Corporation dated April 17, 2003).*
10(iii)(a.2).	Form of stock option granted to executive officers (incorporated by reference to Exhibit 10(iii)(a.2) to the registrant s Annual Report on Form 10-K for 2004).*
10(iii)(a.3).	Form of restricted stock agreement with executive officers (incorporated by reference to Exhibit 99.2 to the Registrant s Report on Form 8-K on December 1, 2006).*
10(iii)(b.1).	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(e) to the registrant s Annual Report on Form 10-K for 2003).*
10(iii)(b.2).	Form of Earnings Bonus Unit granted to executive officers (incorporated by reference to Exhibit 99.1 to the Registrant s Report on Form 8-K on December 1, 2006).*
10(iii)(c.1).	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant s Report on Form 8-K on October 12, 2006).*
10(iii)(c.2).	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant s Report on Form 8-K on October 12, 2006).*
10(iii)(c.3).	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant s Report on Form 8-K on October 12, 2006).*
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 2004).*
10(iii)(f.1).	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Appendix B to the Proxy Statement of Exxon Mobil Corporation dated April 14, 2004).*
10(iii)(f.2).	Standing resolution for non-employee director restricted grants dated July 28, 2004 (incorporated by reference to Exhibit 10(iii)(c.2) to the registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).*
10(iii)(f.3).	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 99.3 to the registrant s Report on Form 8-K on January 4, 2005).*
10(iii)(f.4).	Standing resolution for non-employee director cash fees dated September 27, 2000 (incorporated by reference to Exhibit 10(iii)(f.1) to the registrant s Annual Report on Form 10-K for 2004).*

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10(iii)(f.5).	2001 Nonemployee Directors Deferred Compensation Plan (incorporate by reference to Exhibit 10(iii)(f.5) to the registrant s Annual Report on Form 10-K for 2005).*
10(iii)(g.1).	1995 Mobil Incentive Compensation and Stock Ownership Plan (incorporate by reference to Exhibit 10(iii)(g.1) to the registrant s Annual Report on Form 10-K for 2005).*
10(iii)(g.2).	Form of stock option granted to Mobil executive officers (incorporated by reference to Exhibit 10(iii)(g.2) to the registrant s Annual Report on Form 10-K for 2004).*
12.	Computation of ratio of earnings to fixed charges.
14.	Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the registrant s Annual Report on Form 10-K for 2003).
21.	Subsidiaries of the registrant.
23.	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
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 Financial Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting 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 Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting 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.