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2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2007

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 (5,350,027,205 shares outstanding at January 31, 2008)	**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, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ü   Accelerated filer ___
Non-accelerated filer ___   Smaller reporting company ___

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 29, 2007, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $83.88 on the New York Stock Exchange composite tape, was in excess of $465 billion.

Documents Incorporated by Reference:
Proxy Statement for the 2008 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007

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PART I

Item 1. ***Business.***

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. 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 2007 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $3.8 billion, of which $1.5 billion were capital expenditures and $2.3 billion were included in expenses. The total cost for such activities is expected to remain in this range in 2008 and 2009 (with capital expenditures approximately 45 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 80.8 thousand, 82.1 thousand and 83.7 thousand at years ended 2007, 2006 and 2005, 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 26.3 thousand, 24.3 thousand and 22.4 thousand at years ended 2007, 2006 and 2005, respectively.

ExxonMobil maintains a website at exxonmobil.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commission. Also available on the Corporation's website are the Company's

Corporate Governance Guidelines and Code of Ethics and Business Conduct, as well as the charters of the audit, compensation and nominating committees of the Board of Directors. All of these documents are available in print 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;

- other political developments and laws and regulations, such as expropriation or forced divestiture of assets, unilateral cancellation or modification of contract terms, and 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 2007

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, 2007, 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, 2007. The Corporation has reported 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.

	Liquids	Natural Gas	Oil-Equivalent Basis
	(millions of barrels)	(billions of cubic feet)	(millions of barrels)
United States	1,851	13,172	4,046
Canada/South America	939	1,559	1,199
Europe	673	6,512	`1,758
Africa	2,058	1,006	2,226
Asia Pacific/Middle East	1,510	9,634	3,116
Russia/Caspian	713	727	834
Total consolidated	7,744	32,610	13,179

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

	Year-End 2007		Year-End 2006	
	Developed	Undeveloped	Developed	Undeveloped
	(millions of oil-equivalent barrels)			
Consolidated Subsidiaries				
United States	2,723	1,323	3,013	879
Canada/South America	899	300	1,173	553
Europe	1,362	396	1,448	482
Africa	1,331	895	1,416	837
Asia Pacific/Middle East	2,055	1,061	2,070	814
Russia/Caspian	157	677	183	739
Total	8,527	4,652	9,303	4,304
Equity Companies				
United States	316	79	329	84
Europe	1,621	462	1,675	429
Asia Pacific/Middle East	2,121	2,929	1,948	2,995
Russia/Caspian	637	413	679	364
Total	4,695	3,883	4,631	3,872

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 2008-2012. 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 2007, 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 2006, which shows ExxonMobil’s net interests in all liquids and gas reserve volumes and changes thereto from both ExxonMobil-operated properties and properties operated by others. The data on Form EIA-23, although consistent with the data on Form EIA-28, is presented on a different basis, and includes 100 percent of the oil and gas volumes from ExxonMobil-operated properties only, regardless of the company’s net interest. In addition, Form EIA-23 information does not include gas plant liquids. The difference between the oil reserves and gas reserves reported on EIA-23 and those reported in the registrant's Annual Report on Form 10-K for 2006 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 2007				Year-End 2006			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	27,444	10,320	9,112	5,516	28,139	10,644	9,059	5,468
Canada/South America	5,714	5,092	6,211	3,240	5,816	5,039	5,942	3,088
Europe	1,599	477	1,188	472	1,780	528	1,300	509
Africa	853	350	16	6	823	348	12	5
Asia Pacific/Middle East	2,195	573	272	183	2,191	587	267	184
Russia/Caspian	119	24	—	—	82	17	—	—
Total	37,924	16,836	16,799	9,417	38,831	17,163	16,580	9,254

The numbers of wells operated at year-end 2007 were 16,797 gross wells and 13,945 net wells. At year-end 2006, the numbers of operated wells were 16,914 gross wells and 13,988 net wells.

5. Gross and Net Developed Acreage

	Year-End 2007		Year-End 2006	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	9,001	5,174	9,045	5,178
Canada/South America	5,391	2,337	5,502	2,331
Europe	10,730	4,194	10,678	4,418
Africa	1,889	729	1,842	717
Asia Pacific/Middle East	8,124	1,649	8,210	1,655
Russia/Caspian	531	116	531	116
Total	35,666	14,199	35,808	14,415

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

6. Gross and Net Undeveloped Acreage

	Year-End 2007		Year-End 2006	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	9,104	5,539	9,917	6,062
Canada/South America	32,399	22,353	31,462	22,014
Europe	13,552	6,002	8,089	2,727
Africa	39,935	24,835	39,306	24,075
Asia Pacific/Middle East	20,904	13,167	13,466	7,462
Russia/Caspian	1,952	392	2,181	449
Total	117,846	72,288	104,421	62,789

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 / SOUTH AMERICA

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 and the block in the Beaufort Sea acquired in 2007 are currently held by work commitments of various amounts.

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

Until the recent Venezuelan Government actions described below, exploration and production activities were governed by Association Agreements containing risk/profit provisions negotiated with the national oil company or its affiliates. Association Agreements were awarded for a term not to exceed 39 years. These agreements had an exploration and a production phase. The term of production began after the exploration phase for a duration of 20 years with the possibility of an extension, so long as the total contract term did not exceed 39 years.

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

On February 26, 2007, President Chavez issued Law Decree N° 5200 which mandated the Conversion of the Orinoco Belt Association Agreements (Cerro Negro) and Oil Profit Sharing Agreements (La Ceiba) into Mixed Enterprises (the “Nationalization Decree”). The Nationalization Decree further ordered the transfer of operations to PdVSA Petroleos, S. A. (PdVSA) by April 30, 2007. The ExxonMobil affiliates in Venezuela were unable to reach agreement to migrate to a Mixed Enterprise by June 26, 2007, as required by the Nationalization Decree. Assets were expropriated on June 27, 2007. On September 6, 2007, the ExxonMobil affiliates filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes against Venezuela. ExxonMobil also has filed an arbitration under the rules of the International Chamber of Commerce against PdVSA and a PdVSA affiliate for breach of their contractual obligations under certain Cerro Negro Project agreements.

Refer to the relevant portion of “Note 15: Litigation and Other Contingencies” of the Financial Section of this report for additional information.

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. In May 2007, ExxonMobil affiliates acquired four exploration licenses over 1.3 million acres in the Lower Saxony Basin. The exploration licenses are for a period of five years during which exploration work programs will be carried out.

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.

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. In May 2007, Chad enacted a new Petroleum Code which would govern new acquisitions.

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. In 2000, a Memorandum of Understanding (MOU) was executed defining commercial terms applicable to existing joint venture oil production. The MOU may be terminated on one calendar year's notice.

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.

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 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. Recent amendments of the Oil and Gas Act provide that extensions of Petroleum Retention licenses may be for periods of less than one year, renewable annually, if the Minister considers at the time of extension that the resources could become commercially viable in less than five 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.

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 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.

8. Number of Net Productive and Dry Wells Drilled

	2007	2006	2005
A. Net Productive Exploratory Wells Drilled			
United States	12	10	13
Canada/South America	1	3	1
Europe	2	2	4
Africa	2	4	5
Asia Pacific/Middle East	1	2	1
Russia/Caspian	1	—	—
Total	19	21	24
B. Net Dry Exploratory Wells Drilled			
United States	8	5	5
Canada/South America	1	1	—
Europe	2	2	1
Africa	4	4	5
Asia Pacific/Middle East	1	—	1
Russia/Caspian	—	—	1
Total	16	12	13
C. Net Productive Development Wells Drilled			
United States	451	552	537
Canada/South America	377	373	272
Europe	16	22	19
Africa	43	64	61
Asia Pacific/Middle East	26	25	50
Russia/Caspian	4	5	7
Total	917	1,041	946
D. Net Dry Development Wells Drilled			
United States	15	5	8
Canada/South America	—	1	2
Europe	3	4	2
Africa	1	1	—
Asia Pacific/Middle East	—	—	2
Russia/Caspian	—	—	—
Total	19	11	14
Total number of net wells drilled	971	1,085	997

9. Present Activities

A. Wells Drilling

	Year-End 2007		Year-End 2006	
	Gross	Net	Gross	Net
United States	118	65	214	109
Canada/South America	187	125	226	183
Europe	41	6	55	11
Africa	30	11	50	19
Asia Pacific/Middle East	46	25	49	14
Russia/Caspian	36	5	33	6
Total	458	237	627	342

B. Review of Principal Ongoing Activities in Key Areas

During 2007, 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

ExxonMobil's year-end 2007 acreage holdings totaled 10.7 million net acres, of which 2.1 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During 2007, 459.7 net exploration and development wells were completed in the inland lower 48 states and 4.0 net exploration and development wells were completed offshore in the Pacific. Tight gas development continued in the Piceance Basin of Colorado and the Barnett Shale in Texas. Participation in Alaska production and development continued and a total of 16.7 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 future facility expansions.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2007 was 2.0 million acres. A total of 6.2 net exploration and development wells were completed during the year. Activity on the Thunder Horse project progressed in 2007, including work to rebuild and reinstall subsea equipment resulting from the 2005 listing incident and from subsea manifold failures. Start-up is anticipated in 2008.

The Golden Pass LNG regasification terminal in Texas is under construction. The terminal will have the capacity to supply two billion cubic feet of gas per day.

CANADA / SOUTH AMERICA

Canada

ExxonMobil's year-end 2007 acreage holdings totaled 7.3 million net acres, of which 3.3 million net acres were offshore. A total of 373.8 net exploration and development wells were completed during the year.

Argentina

ExxonMobil's net acreage totaled 0.2 million onshore acres at year-end 2007, and there were 4.3 net development wells completed during the year.

Venezuela

ExxonMobil's acreage holdings and assets were expropriated in 2007. Refer to the relevant portion of "Note 15: Litigation and Other Contingencies" of the Financial Section of this report for additional information.

EUROPE

Germany

A total of 3.1 million net onshore acres and 0.1 million net offshore acres were held by ExxonMobil at year-end 2007, with 5.2 net development and exploration wells drilled during the year.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.6 million acres at year-end 2007, of which 1.3 million acres were onshore. A total of 3.8 net exploration and development wells were completed during the year. The offshore L09 project was progressed while the Waddenzee project started up. The multi-year Groningen onshore project to renovate production clusters, install new compression to maintain capacity and extend field life continued. The project to redevelop the previously abandoned Schoonebeek oil field was approved in 2007.

Norway

ExxonMobil's net interest in licenses at year-end 2007 totaled approximately 0.8 million acres, all offshore. ExxonMobil participated in 7.1 net exploration and development well completions in 2007. The Ormen Lange and Statfjord Late Life projects and the Njord Gas Export project started up in 2007. The Volve and Tyrihans projects are in progress.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2007 totaled approximately 1.6 million acres, all offshore. A total of 6.7 net development wells were completed during the year. Divestment of the mature Southern North Sea operated acreage was completed in 2007 (0.2 million acres). Significant projects progressed during the year include Starling, Caravel, and the St. Fergus gas processing facilities refurbishment. The South Hook LNG regasification terminal in Wales is anticipated to start up in 2008. The terminal will have the capacity to supply two billion cubic feet of gas per day into the natural gas grid.

AFRICA

Angola

ExxonMobil's year-end 2007 acreage holdings totaled 0.7 million net offshore acres. 12.0 net exploration and development wells were completed during the year. On Block 15, development drilling continued on Kizomba A and Kizomba B. The Marimba development project, which was a tie-back to the Kizomba A FPSO, started up in 2007. The Kizomba C Mondo project started up in January 2008 and will be followed by the Kizomba C Saxi/Batuque project later in the year. A block-wide 3D seismic acquisition program began in the fourth quarter of 2007. On the non-operated Block 17, the Rosa project started up in June 2007. The Pazflor project was approved in 2007. Production operations continue at Kizomba A, Kizomba B, Xikomba and the non-operated Girassol, Jasmim and Dalia fields.

Cameroon

ExxonMobil's acreage was 0.1 million net offshore acres.

Chad

ExxonMobil's net year-end 2007 acreage holdings consisted of 3.3 million onshore acres, with 19.6 net exploration and development wells completed during the year. Production began from the Maikeri field.

Equatorial Guinea

ExxonMobil's acreage totaled 0.2 million net offshore acres at year-end 2007, with 4.9 net exploration and development wells completed during the year.

Nigeria

ExxonMobil's net acreage totaled 1.3 million offshore acres at year-end 2007, with 12.8 net exploration and development wells completed during the year. Production was initiated from the Erha North Expansion area in December 2007. Construction continued on the ExxonMobil-operated East Area Natural Gas Liquids II project with startup planned for 2008. A 3D seismic acquisition program was initiated to both enhance resolution of existing fields and target deeper formations. Major contracts on the Usan project are expected to be awarded in early 2008.

ASIA PACIFIC / MIDDLE EAST

Australia

ExxonMobil's net year-end 2007 offshore acreage holdings totaled 2.4 million offshore acres. During 2007, a total of 9.3 net exploration and development wells were drilled. The Kipper gas project was approved for development in 2007.

Indonesia

At year-end 2007, ExxonMobil had 4.9 million net acres, 4.1 million acres offshore and 0.8 million acres onshore, with 0.5 net exploration wells completed during the year. Project activities continued on the Banyu Urip development in the Cepu Contract area.

Japan

ExxonMobil's net offshore acreage was 36 thousand acres at year-end 2007.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.5 million net acres offshore Malaysia at year-end 2007. During the year, a total of 3.5 net development wells were completed. Infill drilling wells were successfully completed at the Tabu B and Angsi platforms. Project-related drilling activity was completed at Tabu B and is currently ongoing at Tabu A. Project work continued on the Jerneh B platform installation.

Papua New Guinea

A total of 0.5 million net onshore acres were held by ExxonMobil at year-end 2007, with 1.3 net exploration and development wells 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 produces 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 2007, 70 (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 2007, ExxonMobil had 1.1 million net acres, 1.0 million acres onshore and 0.1 million acres offshore. During 2007, 8.2 net development and exploration wells were completed.

Qatar LNG capacity volumes at year-end 2007 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, with the offshore facilities completed in January 2007. 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.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2007, with a total of 0.1 net development wells completed during the year.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi oil concessions was 0.6 million acres at year-end 2007, of which 0.4 million acres were onshore and 0.2 million acres offshore. During the year, a total of 5.2 net development and exploration wells were completed. During 2007, work progressed on multiple field development projects, both onshore and offshore, to sustain and increase oil production capacity.

RUSSIA / CASPIAN

Azerbaijan

At year-end 2007, ExxonMobil's net acreage, located in the Caspian Sea offshore of Azerbaijan, totaled 60 thousand acres. At the Azeri-Chirag-Gunashli field, 0.9 net development wells were completed and production ramp-up continued. Construction continued on the Phase 3 Deep Water Gunashli project 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 2007, with 0.9 net exploration and development wells completed during 2007. Initial oil production from the first expansion at Tengiz was achieved in 2007 with activities ongoing to complete the project. Construction of the initial phase of the Kashagan field continued during 2007.

Russia

ExxonMobil's net acreage holdings at year-end 2007 were 0.1 million acres, all offshore. A total of 3.0 net development wells were completed in the Chayvo field during the year and Phase 1 drilling activities are continuing. Full-field production (Phase 1) began in the fourth quarter 2006. 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.

WORLDWIDE EXPLORATION

At year-end 2007, exploration activities were underway in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 45 million net acres were held at year-end 2007, and 1.0 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, mines 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 1.8 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 (located on lease 17) was depleted and ceased production in 2007. 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 830,000 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 2007, this upgrading process yielded 0.843 barrels of synthetic crude oil per barrel of crude bitumen. In 2007 about 38 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 62 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 $3.4 billion at year-end 2007.

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 are within the operating North and Aurora mines. In accordance with the approved mining plan, there are extractable oil sands in the North and Aurora mines, with average bitumen grades of 10.6 and 11.2 weight percent, respectively. 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 2007 was equivalent to 694 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 added a remote mining train and expanded 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.

In 2007, the Alberta government proposed changes to the generic oil sands royalty regime beginning in 2009. The Syncrude Joint Venture owners have a Crown Agreement with the Province of Alberta that codifies the royalty rates through December 31, 2015. The Syncrude Joint Venture owners are in discussions with the Alberta government to determine if an amended agreement can be negotiated that would transition Syncrude to the new generic royalty regime before 2016.

ExxonMobil Share of Net Proven Syncrude Reserves(1)

	Synthetic Crude Oil		
	Base Mine and North Mine	Aurora Mine	Total
		(millions of barrels)	
January 1, 2007	199	519	718
Revision of previous estimate	—	—	—
Production	(11)	(13)	(24)
December 31, 2007	188	506	694

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

Syncrude Operating Statistics (total operation)

	2007	2006	2005	2004	2003
Operating Statistics					
Total mined overburden (millions of cubic yards)(1)	132.2	128.2	97.1	100.3	109.2
Mined overburden to oil sands ratio(1)	1.06	1.18	1.02	0.94	1.15
Oil sands mined (millions of tons)	221.0	195.5	168.0	188.0	168.0
Average bitumen grade (weight percent)	11.6	11.4	11.1	11.1	11.0
Crude bitumen in mined oil sands (millions of tons)	25.6	22.2	18.6	20.9	18.5
Average extraction recovery (percent)	91.8	90.3	89.1	87.3	88.6
Crude bitumen production (millions of barrels)(2)	132.5	111.6	94.2	103.3	92.3
Average upgrading yield (percent)	84.3	84.9	85.3	85.5	86.0
Gross synthetic crude oil produced (millions of barrels)	113.0	95.5	79.3	88.4	78.4
ExxonMobil net share (millions of barrels)(3)	24	21	19	22	19

(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.***

On October 4, 2007, the Company received a proposed agreed order from the Texas Commission on Environmental Quality (TCEQ) relating to an alleged unauthorized air emission event at the Company's Baytown, Texas chemical plant on May 14, 2007. The TCEQ is seeking an administrative penalty of $118,675, and it has referred the matter to its litigation division. ExxonMobil disputes the penalty calculation methodology utilized by the TCEQ. Once this matter is accepted by the State Office for Administrative Hearings, the Company will have the opportunity to meet with the TCEQ to attempt to resolve the penalty calculation dispute.

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.

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

Name	Age as of February 29, 2008	Title (Held Office Since)
R. W. Tillerson	55	Chairman of the Board (2006)
M. W. Albers	51	Senior Vice President (2007)
D. D. Humphreys	60	Senior Vice President (2006) and Treasurer (2004)
J. S. Simon	64	Senior Vice President (2004)
A. T. Cejka	56	Vice President (2004)
H. R. Cramer	57	Vice President (1999)
M. J. Dolan	54	Vice President (2004)
N. W. Duffin	51	President, ExxonMobil Development Company (2007)
M. E. Foster	64	Vice President (2004)
H. H. Hubble	55	Vice President—Investor Relations and Secretary (2004)
A. J. Kelly	50	Vice President (2007)
S. R. LaSala	63	Vice President and General Tax Counsel (2007)
C. W. Matthews	63	Vice President and General Counsel (1995)
P. T. Mulva	56	Vice President and Controller (2004)
S. D. Pryor	58	Vice President (2004)
A. P. Swiger	51	Vice President (2006)

For at least the past five years, Messrs. Cramer, Humphreys, LaSala, Matthews, Mulva, Simon 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. Albers was President of ExxonMobil Development Company before becoming Senior Vice President. Mr. Humphreys was Vice President and Controller and then Vice President and Treasurer before becoming Senior Vice President and Treasurer. Mr. Simon was President of ExxonMobil Refining & Supply Company before becoming Senior Vice President. Mr. LaSala was Associate General Tax Counsel before becoming Vice President and General Tax Counsel. 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, 2007.

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

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.

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, 2007

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, 2007	30,511,333	92.42	30,511,333	
November, 2007	30,452,285	87.25	30,452,285	
December, 2007	26,816,392	91.77	26,816,392	
Total	87,780,010	90.43	87,780,010	(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.***

	2007	2006	2005	2004	2003
	Years Ended December 31, (millions of dollars, except per share amounts)				
Sales and other operating revenue(1)(2)	$ 390,328	$ 365,467	$ 358,955	$ 291,252	$ 237,054
(1) Sales-based taxes included.	*$ 31,728*	*$ 30,381*	*$ 30,742*	*$ 27,263*	*$ 23,855*
(2) Includes amounts for purchases/sales contracts with the same counterparty for 2003-2005.					
Net income					
Income from continuing operations	$ 40,610	$ 39,500	$ 36,130	$ 25,330	$ 20,960
Cumulative effect of accounting change, net of income tax	—	—	—	—	550
Net income	$ 40,610	$ 39,500	$ 36,130	$ 25,330	$ 21,510
Net income per common share					
Income from continuing operations	$ 7.36	$ 6.68	$ 5.76	$ 3.91	$ 3.16
Cumulative effect of accounting change, net of income tax	—	—	—	—	0.08
Net income	$ 7.36	$ 6.68	$ 5.76	$ 3.91	$ 3.24
Net income per common share - assuming dilution					
Income from continuing operations	$ 7.28	$ 6.62	$ 5.71	$ 3.89	$ 3.15
Cumulative effect of accounting change, net of income tax	—	—	—	—	0.08
Net income	$ 7.28	$ 6.62	$ 5.71	$ 3.89	$ 3.23
Cash dividends per common share	$ 1.37	$ 1.28	$ 1.14	$ 1.06	$ 0.98
Total assets	$ 242,082	$ 219,015	$ 208,335	$ 195,256	$ 174,278
Long-term debt	$ 7,183	$ 6,645	$ 6,220	$ 5,013	$ 4,756

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, 2008, 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);

- "Supplemental Information on Oil and Gas Exploration and Production Activities" (unaudited); and
- "Frequently Used Terms" (unaudited).

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, 2007. Based on that evaluation, these officers have concluded that the Corporation's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

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, 2007.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2007, 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.

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 2008 annual meeting of shareholders (the "2008 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 2008 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 2008 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	81,590,508 (2)(3)	$40.82(3)	171,550,342(3)(4)(5)
Equity compensation plans not approved by security holders	0	0	0
Total	81,590,508	$40.82	171,550,342

(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 five prior option grants that are still outstanding.

(2) Includes 73,630,135 options granted under the 1993 Incentive Program and 7,960,373 restricted stock units to be settled in shares.

(3) Does not include options that ExxonMobil assumed in the 1999 merger with Mobil Corporation. At year-end 2007, the number of securities to be issued upon exercise of outstanding options under Mobil Corporation plans was 6,658,578, and the weighted-average exercise price of such options was $30.78. 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 170,695,142 shares available for award under the 2003 Incentive Program and 855,200 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.

(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. Effective January 1, 2008, the annual share grant was changed from 4,000 to 2,500 restricted shares. 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 may 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 provided in response to 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 2008 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 2008 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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BUSINESS PROFILE

Financial	Earnings After Income Taxes 2007	Earnings After Income Taxes 2006	Average Capital Employed 2007	Average Capital Employed 2006	Return on Average Capital Employed 2007	Return on Average Capital Employed 2006	Capital and Exploration Expenditures 2007	Capital and Exploration Expenditures 2006
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	$ 4,870	$ 5,168	$ 14,026	$ 13,940	34.7	37.1	$ 2,212	$ 2,486
Non-U.S.	21,627	21,062	49,539	43,931	43.7	47.9	13,512	13,745
Total	$26,497	$26,230	$ 63,565	$ 57,871	41.7	45.3	$15,724	$16,231
Downstream								
United States	$ 4,120	$ 4,250	$ 6,331	$ 6,456	65.1	65.8	$ 1,128	$ 824
Non-U.S.	5,453	4,204	18,983	17,172	28.7	24.5	2,175	1,905
Total	$ 9,573	$ 8,454	$ 25,314	$ 23,628	37.8	35.8	$ 3,303	$ 2,729
Chemical								
United States	$ 1,181	$ 1,360	$ 4,748	$ 4,911	24.9	27.7	$ 360	$ 280
Non-U.S.	3,382	3,022	8,682	8,272	39.0	36.5	1,422	476
Total	$ 4,563	$ 4,382	$ 13,430	$ 13,183	34.0	33.2	$ 1,782	$ 756
Corporate and financing	(23)	434	26,451	27,891	—	—	44	139
Total	$40,610	$39,500	$128,760	$122,573	31.8	32.2	$20,853	$19,855

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

Operating	2007	2006
	(thousands of barrels daily)	
Net liquids production		
United States	392	414
Non-U.S.	2,224	2,267
Total	2,616	2,681
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	1,468	1,625
Non-U.S.	7,916	7,709
Total	9,384	9,334
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production *(1)*	4,180	4,237
	(thousands of barrels daily)	
Refinery throughput		
United States	1,746	1,760
Non-U.S.	3,825	3,843
Total	5,571	5,603
	(thousands of barrels daily)	
Petroleum product sales		
United States	2,717	2,729
Non-U.S.	4,382	4,518
Total	7,099	7,247
	(thousands of metric tons)	

Chemical prime product sales		
United States	10,855	10,703
Non-U.S.	16,625	16,647
Total	27,480	27,350

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

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FINANCIAL SUMMARY

	2007	2006	2005	2004	2003
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1) (2)*	$390,328	$365,467	$358,955	$291,252	$237,054
Earnings					
Upstream	$ 26,497	$ 26,230	$ 24,349	$ 16,675	$ 14,502
Downstream	9,573	8,454	7,992	5,706	3,516
Chemical	4,563	4,382	3,943	3,428	1,432
Corporate and financing	(23)	434	(154)	(479)	1,510
Income from continuing operations	$ 40,610	$ 39,500	$ 36,130	$ 25,330	$ 20,960
Cumulative effect of accounting change, net of income tax	—	—	—	—	550
Net income	$ 40,610	$ 39,500	$ 36,130	$ 25,330	$ 21,510
Net income per common share					
Income from continuing operations	$ 7.36	$ 6.68	$ 5.76	$ 3.91	$ 3.16
Net income per common share – assuming dilution					
Income from continuing operations	$ 7.28	$ 6.62	$ 5.71	$ 3.89	$ 3.15
Cumulative effect of accounting change, net of income tax	—	—	—	—	0.08
Net income	$ 7.28	$ 6.62	$ 5.71	$ 3.89	$ 3.23
Cash dividends per common share	$ 1.37	$ 1.28	$ 1.14	$ 1.06	$ 0.98
Net income to average shareholders' equity (percent)	34.5	35.1	33.9	26.4	26.2
Working capital	$ 27,651	$ 26,960	$ 27,035	$ 17,396	$ 7,574
Ratio of current assets to current liabilities	1.47	1.55	1.58	1.40	1.20
Additions to property, plant and equipment	$ 15,387	$ 15,462	$ 13,839	$ 11,986	$ 12,859
Property, plant and equipment, less allowances	$120,869	$113,687	$107,010	$108,639	$104,965
Total assets	$242,082	$219,015	$208,335	$195,256	$174,278
Exploration expenses, including dry holes	$ 1,469	$ 1,181	$ 964	$ 1,098	$ 1,010
Research and development costs	$ 814	$ 733	$ 712	$ 649	$ 618
Long-term debt	$ 7,183	$ 6,645	$ 6,220	$ 5,013	$ 4,756
Total debt	$ 9,566	$ 8,347	$ 7,991	$ 8,293	$ 9,545
Fixed-charge coverage ratio (times)	49.9	46.3	50.2	36.1	30.8
Debt to capital (percent)	7.1	6.6	6.5	7.3	9.3
Net debt to capital (percent) *(3)*	(24.0)	(20.4)	(22.0)	(10.7)	(1.2)
Shareholders' equity at year end	$121,762	$113,844	$111,186	$101,756	$ 89,915
Shareholders' equity per common share	$ 22.62	$ 19.87	$ 18.13	$ 15.90	$ 13.69
Weighted average number of common shares outstanding (millions)	5,517	5,913	6,266	6,482	6,634
Number of regular employees at year end (thousands) *(4)*	80.8	82.1	83.7	85.9	88.3
CORS employees not included above (thousands) *(5)*	26.3	24.3	22.4	19.3	17.4

(1) Sales and other operating revenue includes sales-based taxes of $31,728 million for 2007, $30,381 million for 2006, $30,742 million for 2005, $27,263 million for 2004 and $23,855 million for 2003.

(2) Sales and other operating revenue includes $30,810 million for 2005, $25,289 million for 2004 and $20,936 million for 2003 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.

(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 reflects 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	**2007**	**2006**	**2005**
		(millions of dollars)	
Net cash provided by operating activities	$52,002	$49,286	$48,138
Sales of subsidiaries, investments and property, plant and equipment	4,204	3,080	6,036
Cash flow from operations and asset sales	$56,206	$52,366	$54,174

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	**2007**	**2006**	**2005**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	$242,082	$219,015	$208,335
Less liabilities and minority share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(55,929)	(47,115)	(44,536)
Total long-term liabilities excluding long-term debt and equity of minority and preferred shareholders in affiliated companies	(50,543)	(45,905)	(41,095)
Minority share of assets and liabilities	(5,332)	(4,948)	(4,863)
Add ExxonMobil share of debt-financed equity company net assets	3,386	2,808	3,450
Total capital employed	$133,664	$123,855	$121,291
Total corporate sources: debt and equity perspective			
Notes and loans payable	$ 2,383	$ 1,702	$ 1,771
Long-term debt	7,183	6,645	6,220
Shareholders' equity	121,762	113,844	111,186
Less minority share of total debt	(1,050)	(1,144)	(1,336)
Add ExxonMobil share of equity company debt	3,386	2,808	3,450
Total capital employed	$133,664	$123,855	$121,291

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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 are more cash flow-based, are used to make investment decisions.

Return on average capital employed	**2007**	**2006**	**2005**
		(millions of dollars)	
Net income	$ 40,610	$ 39,500	$ 36,130
Financing costs (after tax)			
Gross third-party debt	(339)	(264)	(261)
ExxonMobil share of equity companies	(204)	(156)	(144)
All other financing costs – net	268	499	(35)
Total financing costs	(275)	79	(440)
Earnings excluding financing costs	$ 40,885	$ 39,421	$ 36,570
Average capital employed	$128,760	$122,573	$116,961
Return on average capital employed – corporate total	31.8%	32.2%	31.3%

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QUARTERLY INFORMATION

	2007					2006				
	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	2,746	2,668	2,537	2,517	2,616	2,698	2,702	2,647	2,678	2,681
Refinery throughput	5,705	5,279	5,582	5,717	5,571	5,548	5,407	5,756	5,698	5,603
Petroleum product sales	7,198	6,973	7,100	7,125	7,099	7,177	7,060	7,302	7,447	7,247
					(millions of cubic feet daily)					
Natural gas production available for sale	10,114	8,733	8,283	10,414	9,384	11,175	8,754	8,139	9,301	9,334
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(1)*	4,432	4,123	3,918	4,253	4,180	4,560	4,161	4,004	4,228	4,237
					(thousands of metric tons)					
Chemical prime product sales	6,805	6,897	6,729	7,049	27,480	6,916	6,855	6,752	6,827	27,350
Summarized financial data										
					(millions of dollars)					
Sales and other operating revenue *(2)*	$ 84,174	95,059	99,130	111,965	390,328	$ 86,317	96,024	96,268	86,858	365,467
Gross profit *(3)*	$ 33,907	36,760	36,114	39,914	146,695	$ 33,428	37,668	37,117	33,764	141,977
Net income	$ 9,280	10,260	9,410	11,660	40,610	$ 8,400	10,360	10,490	10,250	39,500
Per share data										
					(dollars per share)					
Net income per common share	$ 1.64	1.85	1.72	2.15	7.36	$ 1.38	1.74	1.79	1.77	6.68
Net income per common share – assuming dilution	$ 1.62	1.83	1.70	2.13	7.28	$ 1.37	1.72	1.77	1.76	6.62
Dividends per common share	$ 0.32	0.35	0.35	0.35	1.37	$ 0.32	0.32	0.32	0.32	1.28
Common stock prices										
High	$ 76.35	86.58	93.66	95.27	95.27	$ 63.96	65.00	71.22	79.00	79.00
Low	$ 69.02	75.28	78.76	83.37	69.02	$ 56.42	56.64	61.63	64.84	56.42

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.
(2) Includes amounts for sales-based taxes.
(3) 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 566,565 registered shareholders of ExxonMobil common stock at December 31, 2007. At January 31, 2008, the registered shareholders of ExxonMobil common stock numbered 561,103.

On January 30, 2008, the Corporation declared a $0.35 dividend per common share, payable March 10, 2008.

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

FUNCTIONAL EARNINGS	2007	2006	2005
	(millions of dollars, except per share amounts)		
Net income (U.S. GAAP)			
Upstream			
United States	$ 4,870	$ 5,168	$ 6,200
Non-U.S.	21,627	21,062	18,149
Downstream			
United States	4,120	4,250	3,911
Non-U.S.	5,453	4,204	4,081
Chemical			
United States	1,181	1,360	1,186
Non-U.S.	3,382	3,022	2,757
Corporate and financing	(23)	434	(154)
Net income	$ 40,610	$ 39,500	$ 36,130
Net income per common share	$ 7.36	$ 6.68	$ 5.76
Net income per common share – assuming dilution	$ 7.28	$ 6.62	$ 5.71
Special items included in net income			
Non-U.S. Upstream			
Gain on Dutch gas restructuring	$ —	$ —	$ 1,620
U.S. Downstream			
Allapattah lawsuit provision	$ —	$ —	$ (200)
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	$ —

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 2007 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 89 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 business 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 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 are utilized 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.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2030, the world's population is projected to grow to approximately 8 billion, more than 20 percent higher than today's level. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. This combination of population and economic growth is expected to lead to a primary energy demand increase of approximately 40 percent by 2030 versus 2005. 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 rate of improvement projected to increase. Efficiency gains will result from anticipated improvements in the transportation and power generation sectors, driven by the introduction of new technologies, as well as many other improvements that span the residential, commercial and industrial sectors. A wide variety of energy sources will be required to meet increasing global demand. Oil, gas and coal are expected to remain the predominant energy sources with approximately 80 percent share of total energy. Oil and gas are projected 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 over the outlook period. Nuclear power will likely be a growing option to meet electricity needs. Among renewable energy sources, wind, solar and biofuels are anticipated to grow rapidly at about 9 percent per year, reflecting government subsidies and mandates. These energy sources are projected to reach approximately 2 percent of world energy by 2030, up from 0.5 percent currently.

Demand for liquid fuels is expected to grow at 1.3 percent per year from 2005 to 2030, 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 projected to grow at 1.7 and 0.9 percent per year, respectively, driven by rising needs for electric power generation. The Corporation expects the liquefied natural gas (LNG) market to increase over 250 percent 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 anticipates that the world's oil and gas resource base will 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 $380 billion per year, or about $9.5 trillion (measured in 2006 dollars) in total for 2006-2030.

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 2012. 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 38 percent of the Corporation's production. By 2012, 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, North America and Asia Pacific.

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 percent to over 40 percent of the Corporation's output between now and 2012. The Corporation's overall volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the period 2008-2012. 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 under production sharing contracts and other factors described in Item 1A of ExxonMobil's 2007 Form 10-K.

Downstream

ExxonMobil's Downstream is a large, diversified business with marketing and refining complexes around the world. The Corporation has a strong presence in mature markets as well as in growing areas, such as the Asia Pacific region. The objective of ExxonMobil's Downstream strategies is 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 quality, valued products and services to the Corporation's customers.

The downstream industry environment remains very competitive. Refining margins have been relatively strong over the past few years. However, inflation-adjusted refining margins over the prior 20 years have declined at a rate of about 1 percent per year. The intense competition in the retail fuels market has similarly driven down inflation-adjusted margins by about 3 percent per year. 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, diesel 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 IntercontinentalExchange). Prices for these commodities (crude and various products) are determined by the global marketplace and are influenced by many factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, seasonal demand, weather and political climate.

ExxonMobil has an ownership interest in 38 refineries, located in 21 countries, with distillation capacity of 6.3 million barrels per day and lubricant basestock manufacturing capacity of about 140 thousand barrels per day. ExxonMobil's fuels and lubes marketing business portfolios include operations around the world, serving a globally diverse customer base.

ExxonMobil's Downstream capital expenditures are focused on selective and resilient investments. These investments capitalize on the Corporation's world-class scale and integration, industry-leading efficiency, leading-edge technology and respected brands, enabling ExxonMobil to take advantage of attractive emerging-growth opportunities around the globe. For example, in mid-2007, ExxonMobil along with our partners Saudi Aramco, Sinopec and the Fujian Province formed the only fully integrated refining, petrochemicals and fuels marketing venture with foreign participation in China. In addition, ExxonMobil successfully started up several projects that produce lower-sulfur motor fuels, including gasoline projects in Japan and diesel projects in North America and Europe, with additional start-ups planned for 2008.

Chemical

The strength of the global economy supported continued solid demand growth for petrochemicals in 2007. Strong economic and industrial production growth increased demand in Asia Pacific, particularly China. North American and European growth were moderate, similar to that of GDP. Overall the global supply/demand balance remained tight, supporting continued strong 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 2007 AND 2006 RESULTS

	2007	2006	2005
		(millions of dollars)	
Net income (U.S. GAAP)	$40,610	$ 39,500	$36,130

2007

Net income in 2007 of $40,610 million was the highest ever for the Corporation, up $1,110 million from 2006. Net income for 2006 included a $410 million gain from the recognition of tax benefits related to historical investments in non-U.S. assets. Earnings in 2007 were also at record levels for each business segment.

2006

Net income in 2006 of $39,500 million was 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.

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

Upstream

	2007	2006	2005
	(millions of dollars)		
Upstream			
United States	$ 4,870	$ 5,168	$ 6,200
Non-U.S.	21,627	21,062	18,149
Total	$26,497	$26,230	$24,349

2007

Upstream earnings for 2007 totaled $26,497 million, an increase of $267 million from 2006. Higher liquids realizations were mostly offset by higher operating expenses and net unfavorable tax effects. Oil-equivalent production decreased 1 percent versus 2006, including the Venezuela expropriation, divestments, OPEC quota effects and price and spend impacts on volumes. Excluding these impacts, total oil-equivalent production increased by 1 percent. Liquids production of 2,616 kbd (thousands of barrels per day) decreased by 65 kbd from 2006. Production increases from new projects in West Africa and higher Russia volumes were offset by mature field decline and production sharing contract net interest reductions. Natural gas production of 9,384 mcfd (millions of cubic feet per day) increased 50 mcfd from 2006. Higher volumes from projects in Qatar and the North Sea were mostly offset by mature field decline. Earnings from U.S. Upstream operations for 2007 were $4,870 million, a decrease of $298 million. Earnings outside the U.S. for 2007 were $21,627 million, an increase of $565 million.

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. Liquids production of 2,681 kbd 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 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.

Downstream

	2007	2006	2005
	(millions of dollars)		
Downstream			
United States	$4,120	$4,250	$3,911
Non-U.S.	5,453	4,204	4,081
Total	$9,573	$8,454	$7,992

2007

Downstream earnings totaled $9,573 million, an increase of $1,119 million from 2006. Improved worldwide refining operations and higher gains on asset sales, primarily outside the U.S., were partly offset by lower refining margins. Petroleum product sales of 7,099 kbd decreased from 7,247 kbd in 2006, primarily due to divestment impacts. Refinery throughput was 5,571 kbd compared with 5,603 kbd in 2006, with the decrease again due to divestments. U.S. Downstream earnings of $4,120 million decreased by $130 million. Non-U.S. Downstream earnings of $5,453 million were $1,249 million higher than 2006.

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.

Chemical

	2007	2006	2005
	(millions of dollars)		
Chemical			
United States	$1,181	$1,360	$1,186
Non-U.S.	3,382	3,022	2,757
Total	$4,563	$4,382	$3,943

2007

Chemical earnings totaled $4,563 million, an increase of $181 million from 2006. Increased 2007 earnings were driven by higher sales volumes and favorable foreign exchange effects partly offset by lower margins. Prime product sales were 27,480 kt (thousands of metric tons), an increase of 130 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 $1,181 million decreased by $179 million. Non-U.S. Chemical earnings of $3,382 million were $360 million higher than 2006.

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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, an increase of 573 kt. U.S. Chemical earnings of $1,360 million increased by $174 million. Non-U.S. Chemical earnings of $3,022 million were $265 million higher than 2005 earnings, which included gains from the favorable resolution of joint venture litigation and the Sinopec share sale.

Corporate and Financing

	2007	2006	2005
		(millions of dollars)	
Corporate and financing	$(23)	$434	$(154)

2007

Corporate and financing expenses were $23 million in 2007, compared to an earnings contribution of $434 million in 2006, which included a $410 million gain from tax benefits related to historical investments in non-U.S. assets.

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.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2007	2006
	(millions of dollars)	
Net cash provided by/(used in)		
Operating activities	$ 52,002	$ 49,286
Investing activities	(9,728)	(14,230)
Financing activities	(38,345)	(36,210)
Effect of exchange rate changes	1,808	727
Increase/(decrease) in cash and cash equivalents	$ 5,737	$ (427)
	(Dec. 31)	
Cash and cash equivalents	$ 33,981	$ 28,244
Cash and cash equivalents – restricted	—	4,604
Total cash and cash equivalents	$ 33,981	$ 32,848

Cash and cash equivalents were $34.0 billion at the end of 2007, $5.7 billion higher than the prior year, reflecting a $4.6 billion increase due to the release of the restriction on the restricted cash and cash equivalents and $1.8 billion of positive foreign exchange effects from the weakening of the U.S. dollar in 2007. There were no restricted cash and cash equivalents at the end of 2007 (see note 3 and note 15).

Cash and cash equivalents were $28.2 billion at the end of 2006, comparable to the prior year, as a net reduction from operating, investing and financing activities was partly offset by $0.7 billion of positive foreign exchange effects from the weakening of the U.S. dollar in 2006. Including restricted cash and cash equivalents of $4.6 billion (see note 3 and note 15), total cash and cash equivalents were $32.8 billion at the end of 2006. 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 has access to short-term liquidity, 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.

To support cash flows in future periods 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. 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 the Corporation’s existing oil and gas fields and without new projects, ExxonMobil’s production is expected to decline at approximately 6 percent per year, 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 net interest in production 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 2007 were $20.9 billion, reflecting the Corporation’s continued active investment program. The Corporation expects spending in the range from $25 billion to $30 billion for the next several years. Actual spending could vary depending on the 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.

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

Cash Flow from operating activities

2007

Cash provided by operating activities totaled $52.0 billion in 2007, a $2.7 billion increase from 2006. The major source of funds was net income of $40.6 billion, adjusted for the noncash provision of $12.3 billion for depreciation and depletion, both of which increased.

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.

Cash Flow from Investing Activities

2007

Cash used in investing activities netted to $9.7 billion in 2007, $4.5 billion lower than in 2006. Spending for property, plant and equipment of $15.4 billion in 2007 was comparable to the prior year. Proceeds from the sales of subsidiaries, investments and property, plant and equipment of $4.2 billion in 2007 increased $1.1 billion, reflecting a higher level of asset sales in the Downstream business. Additions from the release of the restriction on the restricted cash and cash equivalents were $4.6 billion. Net investments and advances and net additions to marketable securities were $1.3 billion higher in 2007.

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.

Cash Flow from Financing Activities

2007

Cash used in financing activities was $38.3 billion, an increase of $2.1 billion from 2006, reflecting a higher level of purchases of ExxonMobil shares. Dividend payments on common shares increased to $1.37 per share from $1.28 per share and totaled $7.6 billion, a payout of 19 percent. Total consolidated short-term and long-term debt increased $1.2 billion to $9.6 billion at year-end 2007.

Shareholders' equity increased $7.9 billion in 2007, to $121.8 billion, reflecting $40.6 billion of net income reduced by distributions to ExxonMobil shareholders of $7.6 billion of dividends and $28.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. Shareholders' equity, and net assets and liabilities, increased $4.2 billion, representing the foreign exchange translation effects of stronger foreign currencies at the end of 2007 on ExxonMobil's operations outside the United States.

During 2007, Exxon Mobil Corporation purchased 386 million shares of its common stock for the treasury at a gross cost of $31.8 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 6.1 percent from 5,729 million at the end of 2006 to 5,382 million at the end of 2007. 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.

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 16) 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.

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Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2007. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

Commitments	Note Reference Number	Payments Due by Period 2008	2009-2012	2013 and Beyond	Total
		(millions of dollars)			
Long-term debt (1)	13	$ —	$2,910	$4,273	$ 7,183
– Due in one year (2)		318	—	—	318
Asset retirement obligations (3)	8	307	1,182	3,652	5,141
Pension and other postretirement obligations (4)	16	1,392	3,654	7,851	12,897
Operating leases (5)	10	1,994	5,358	2,564	9,916
Unconditional purchase obligations (6)	15	490	1,497	778	2,765
Take-or-pay obligations (7)		956	2,851	2,369	6,176
Firm capital commitments (8)		7,290	6,332	1,512	15,134

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. The table also excludes net unrecognized tax benefits totaling $4.5 billion as of December 31, 2007, because the Corporation is unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can be found in note 18, Income, Sales-Based and Other Taxes.

Notes:

(1) Includes capitalized lease obligations of $409 million.

(2) The amount due in one year is included in notes and loans payable of $2,383 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 2008 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 $2,765 million mainly pertain to pipeline throughput agreements and include $1,847 million of obligations to equity companies. The present value of the total commitments, which excludes imputed interest of $562 million, was $2,203 million.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $6,176 million mainly pertain to manufacturing supply, pipeline and terminaling agreements and include $1,526 million of obligations to equity companies. The present value of the total commitments, which excludes imputed interest of $1,308 million, totaled $4,868 million.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $15.1 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $5.5 billion was associated with West African projects. 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, 2007, for $5,148 million, primarily relating to guarantees for notes, loans and performance under contracts (note 15). Included in this amount were guarantees by consolidated affiliates of $4,591 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, 2007 Equity Company Obligations	Other Third-Party Obligations	Total
	(millions of dollars)		
Total guarantees	$ 4,591	$ 557	$5,148

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

Financial Strength

On December 31, 2007, unused credit lines for short-term financing totaled approximately $5.7 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 & Poor's (AAA) and Moody's (Aaa), a rating it has sustained for 89 years.

	2007	2006	2005
Fixed-charge coverage ratio (times)	49.9	46.3	50.2
Debt to capital (percent)	7.1	6.6	6.5
Net debt to capital (percent)	(24.0)	(20.4)	(22.0)
Credit rating	AAA/Aaa	AAA/Aaa	AAA/Aaa

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

Litigation

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 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. On May 23, 2007, with two dissenting opinions, the Ninth Circuit determined not to re-hear ExxonMobil's appeal before the full court. ExxonMobil filed a petition for writ of certiorari to the U.S. Supreme Court on August 20, 2007. On October 29, 2007, the U.S. Supreme Court granted ExxonMobil's petition for a writ of certiorari. Oral argument was held on February 27, 2008. 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 appealed the decision to the Alabama Supreme Court. On November 1, 2007, the Alabama Supreme Court reversed the trial court's fraud judgment and instructed the district court to enter judgment for ExxonMobil on the fraud claim, eliminating the punitive damage award. The Court also ruled in ExxonMobil's favor on some of the disputed lease issues, reducing the compensatory award to $52 million plus interest. Following the Alabama Supreme Court's decision, an appeal bond was canceled and the collateral was subsequently released.

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*. On August 8, 2007, the Fourth Circuit issued its decision on remand and declined to reduce the punitive damage award. On November 16, 2007, the Louisiana Supreme Court denied ExxonMobil's writ for review of the Fourth Circuit's decision. ExxonMobil has appealed to the U.S. Supreme Court.

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 beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Other Contingencies

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and owned by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulation that if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assume the activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by PdVSA, and on June 27, 2007, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project.

To date, discussions with Venezuelan authorities have not resulted in an agreement on the amount of compensation to be paid to ExxonMobil. On September 6, 2007, ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes. ExxonMobil has also filed an arbitration under the rules of the International Chamber of Commerce against PdVSA and a PdVSA affiliate for breach of their contractual obligations under certain Cerro Negro Project agreements. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition. At the time the assets were expropriated, ExxonMobil's remaining net book investment in Cerro Negro producing assets was about $750 million.

CAPITAL AND EXPLORATION EXPENDITURES

	2007		2006	
	U.S.	Non-U.S.	U.S.	Non-U.S.
	(millions of dollars)			
Upstream *(1)*	$2,212	$13,512	$2,486	$13,745
Downstream	1,128	2,175	824	1,905
Chemical	360	1,422	280	476
Other	44	—	130	9
Total	$3,744	$17,109	$3,720	$16,135

(1) Exploration expenses included.

Capital and exploration expenditures in 2007 were $20.9 billion, reflecting the Corporation's continued active investment program. The Corporation expects annual expenditures to range from $25 billion to $30 billion for the next several years. Actual spending could vary depending on the progress of individual projects.

Upstream spending of $15.7 billion in 2007 was down 3 percent from 2006, mainly due to timing of project implementation and related expenditures. During the past three years, Upstream capital and exploration expenditures averaged $15.5 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 $3.3 billion in 2007, an increase of $0.6 billion from 2006, as a result of new investment in China and higher environmental expenditures. Chemical 2007 capital expenditures of $1.8 billion were up $1.0 billion from 2006 due to increased investment in Singapore and China to meet Asia Pacific demand growth.

TAXES

	2007	2006	2005
	(millions of dollars)		
Income taxes	$ 29,864	$ 27,902	$23,302
Sales-based taxes	31,728	30,381	30,742
All other taxes and duties	44,091	42,393	44,571
Total	$105,683	$100,676	$98,615
Effective income tax rate	44%	43%	41%

2007

Income, sales-based and all other taxes totaled $105.7 billion in 2007, an increase of $5.0 billion or 5 percent from 2006. Income tax expense, both current and deferred, was $29.9 billion, $2.0 billion higher than 2006, reflecting higher pre-tax income in 2007. The effective tax rate was 44 percent in 2007, compared to 43 percent in 2006. Sales-based and all other taxes and duties of $75.8 billion in 2007 increased $3.0 billion from 2006, reflecting higher prices.

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.

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

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2007	2006
	(millions of dollars)	
Capital expenditures	$ 1,525	$ 1,081
Other expenditures	2,272	2,127
Total	$ 3,797	$ 3,208

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 2007 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $3.8 billion. The total cost for such activities is expected to remain in this range in 2008 and 2009 (with capital expenditures approximately 45 percent of the total).

Environmental Liabilities

The Corporation accrues 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 2007 for environmental liabilities were $432 million ($350 million in 2006) and the balance sheet reflects accumulated liabilities of $916 million as of December 31, 2007, and $864 million as of December 31, 2006.

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 ($113 million for 2007). Over time, the liabilities are accreted for the increase in their present value, with this effect included in expenses ($322 million in 2007). Consolidated company expenditures for asset retirement obligations in 2007 were $352 million and the ending balance of the obligations recorded on the balance sheet at December 31, 2007, totaled $5,141 million.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations ***(1)***	2007	2006	2005
Crude oil and NGL ($/barrel)	$66.02	$58.34	$48.23
Natural gas ($/kcf)	5.29	6.08	5.96

(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 2007 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 & 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.

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 an 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 2007 and 2006.

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

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 157 (FAS 157), "Fair Value Measurements." FAS 157 defines fair value, establishes a framework for measuring fair value when an entity is required to use a fair value measure for recognition or disclosure purposes and expands the disclosures about fair value measurements.

FAS 157 must be adopted by the Corporation no later than January 1, 2008, for all financial assets and liabilities that are measured at fair value and nonfinancial assets and liabilities that are remeasured at fair value at least annually. FAS 157 must be adopted no later than January 1, 2009, for nonfinancial assets and liabilities that are not remeasured at fair value at least annually. The Corporation does not expect the adoption of FAS 157 to have a material impact on the Corporation's financial statements.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued Statement No. 160 (FAS 160), "Noncontrolling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51." FAS 160 changes the accounting and reporting for minority interests, which will be recharacterized as non-controlling interests and classified as a component of equity.

FAS 160 must be adopted by the Corporation no later than January 1, 2009. FAS 160 requires retrospective adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of FAS 160 will be applied prospectively. The Corporation does not expect the adoption FAS 160 to have a material impact on the Corporation's financial statements.

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

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 include both 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 reporting as proved.

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.

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. We understand that the use of December 31 prices and costs is intended to provide a point in time measure to calculate reserves and to enhance comparability between companies.

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 in 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.

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. Volumes are based on individual field production profiles, which are updated annually. 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 consolidated financial statements. The standardized measure of discounted future cash flows is based on the year-end 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 2007 are disclosed in note 9 to the financial statements.

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

Consolidations

The Consolidated Financial Statements include the accounts of those 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, advances and long-term receivables"; 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.

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. Pension and Other Postretirement Benefits (note 16) 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 2007 was 9.0 percent. This compares to an actual rate of return over the past decade of 10 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 long-term rate of return on assets would increase annual pension expense by approximately $140 million before tax.

Differences between actual returns on fund assets and 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.

Litigation Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation 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.

Tax Contingencies

The Corporation is subject to income taxation in many jurisdictions around the world. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict.

GAAP requires recognition and measurement of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns. The benefit of an uncertain tax position can only be recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken in an income tax return and the amount recognized in the financial statements. The Corporation’s unrecognized tax benefits and a description of open tax years are summarized in note 18.

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 countries with a history of high inflation (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; the history of inflation in the country; 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.

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, 2007.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2007, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson
Chief Executive Officer

Donald D. Humphreys
Sr. Vice President and Treasurer
(Principal Financial Officer)

Patrick T. Mulva
Vice President and Controller
(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PRICEWATERHOUSECOOPERS

To the Shareholders of Exxon Mobil Corporation:

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, 2007, and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corporation's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Corporation's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Corporation changed its method of accounting for uncertainty in income taxes in 2007.

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.

PricewaterhouseCoopers LLP

Dallas, Texas
February 28, 2008

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2007	2006	2005
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1) (2)*		$390,328	$365,467	$358,955
Income from equity affiliates	6	8,901	6,985	7,583
Other income		5,323	5,183	4,142
Total revenues and other income		$404,552	$377,635	$370,680
Costs and other deductions				
Crude oil and product purchases		$199,498	$182,546	$185,219
Production and manufacturing expenses		31,885	29,528	26,819
Selling, general and administrative expenses		14,890	14,273	14,402
Depreciation and depletion		12,250	11,416	10,253
Exploration expenses, including dry holes		1,469	1,181	964
Interest expense		400	654	496
Sales-based taxes *(1)*	18	31,728	30,381	30,742
Other taxes and duties	18	40,953	39,203	41,554
Income applicable to minority and preferred interests		1,005	1,051	799
Total costs and other deductions		$334,078	$310,233	$311,248
Income before income taxes		$ 70,474	$ 67,402	$ 59,432
Income taxes	18	29,864	27,902	23,302
Net income		$ 40,610	$ 39,500	$ 36,130
Net income per common share (dollars)	11	$ 7.36	$ 6.68	$ 5.76
Net income per common share – assuming dilution (dollars)	11	$ 7.28	$ 6.62	$ 5.71

(1) *Sales and other operating revenue includes sales-based taxes of $31,728 million for 2007, $30,381 million for 2006 and $30,742 million for 2005.*

(2) *Sales and other operating revenue includes $30,810 million for 2005 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 2007	Dec. 31 2006
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		$ 33,981	$ 28,244
Cash and cash equivalents – restricted	3, 15	—	4,604
Marketable securities		519	—
Notes and accounts receivable, less estimated doubtful amounts	5	36,450	28,942
Inventories			
Crude oil, products and merchandise	3	8,863	8,979
Materials and supplies		2,226	1,735
Prepaid taxes and expenses		3,924	3,273
Total current assets		$ 85,963	$ 75,777
Investments, advances and long-term receivables	7	28,194	23,237
Property, plant and equipment, at cost, less accumulated depreciation and depletion	8	120,869	113,687
Other assets, including intangibles, net		7,056	6,314
Total assets		$ 242,082	$ 219,015
Liabilities			
Current liabilities			
Notes and loans payable	5	$ 2,383	$ 1,702
Accounts payable and accrued liabilities	5	45,275	39,082
Income taxes payable		10,654	8,033
Total current liabilities		$ 58,312	$ 48,817
Long-term debt	13	7,183	6,645
Postretirement benefits reserves	16	13,278	13,931
Deferred income tax liabilities	18	22,899	20,851
Other long-term obligations		14,366	11,123
Equity of minority and preferred shareholders in affiliated companies		4,282	3,804
Total liabilities		$ 120,320	$ 105,171
Commitments and contingencies	15		
Shareholders' equity			
Common stock without par value		$ 4,933	$ 4,786
(9,000 million shares authorized, 8,019 million shares issued)			
Earnings reinvested		228,518	195,207
Accumulated other comprehensive income			
Cumulative foreign exchange translation adjustment		7,972	3,733
Postretirement benefits reserves adjustment		(5,983)	(6,495)
Common stock held in treasury (2,637 million shares in 2007 and 2,290 million shares in 2006)		(113,678)	(83,387)
Total shareholders' equity		$ 121,762	$ 113,844
Total liabilities and shareholders' equity		$ 242,082	$ 219,015

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

	Note Reference Number	2007 Shareholders' Equity	2007 Comprehensive Income	2006 Shareholders' Equity	2006 Comprehensive Income *(1)*	2005 Shareholders' Equity	2005 Comprehensive Income
				(millions of dollars)			
Common stock							
At beginning of year		$ 4,786		$ 4,477		$ 4,053	
Restricted stock amortization		531		480		356	
Tax benefits related to stock-based awards		113		169		224	
Cumulative effect of accounting change	2	(55)		—		—	
Other		(442)		(340)		(156)	
At end of year		$ 4,933		$ 4,786		$ 4,477	
Earnings reinvested							
At beginning of year		195,207		163,335		134,390	
Net income for the year		40,610	$ 40,610	39,500	$ 39,500	36,130	$ 36,130
Cumulative effect of accounting change	2	322		—		—	
Dividends – common shares		(7,621)		(7,628)		(7,185)	
At end of year		$ 228,518		$ 195,207		$ 163,335	
Accumulated other comprehensive income							
At beginning of year		(2,762)		(1,279)		1,527	
Foreign exchange translation adjustment		4,239	4,239	2,754	2,754	(2,619)	(2,619)
Postretirement benefits reserves adjustment	16	(326)	(326)	(6,495)	—	—	—
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs	16	838	838	—	—	—	—
Minimum pension liability adjustment		—	—	2,258	749	241	241
Reclassification adjustment for gain on sale of stock investment included in net income		—	—	—	—	(428)	(428)
At end of year		$ 1,989		$ (2,762)		$ (1,279)	
Total			$ 45,361		$ 43,003		$ 33,324
Common stock held in treasury							
At beginning of year		(83,387)		(55,347)		(38,214)	
Acquisitions, at cost		(31,822)		(29,558)		(18,221)	
Dispositions		1,531		1,518		1,088	
At end of year		$ (113,678)		$ (83,387)		$ (55,347)	
Shareholders' equity at end of year		$ 121,762		$ 113,844		$ 111,186	

	Share Activity 2007	Share Activity 2006	Share Activity 2005
		(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	(2,290)	(1,886)	(1,618)
Acquisitions	(386)	(451)	(311)
Dispositions	39	47	43
At end of year	(2,637)	(2,290)	(1,886)
Common shares outstanding at end of year	5,382	5,729	6,133

(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	2007	2006	2005
			(millions of dollars)	
Cash flows from operating activities				
Net income				
Accruing to ExxonMobil shareholders		$ 40,610	$ 39,500	$ 36,130
Accruing to minority and preferred interests		1,005	1,051	799
Adjustments for noncash transactions				
Depreciation and depletion		12,250	11,416	10,253
Deferred income tax charges/(credits)		124	1,717	(429)
Postretirement benefits expense in excess of/(less than) payments		(1,314)	(1,787)	254
Other long-term obligation provisions in excess of/(less than) payments		1,065	(666)	398
Dividends received greater than/(less than) equity in current earnings of equity companies		(714)	(579)	(734)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) – Notes and accounts receivable		(5,441)	(181)	(3,700)
– Inventories		72	(1,057)	(434)
– Prepaid taxes and expenses		280	(385)	(7)
Increase/(reduction) – Accounts and other payables		6,228	1,160	7,806
Net (gain) on asset sales	4	(2,217)	(1,531)	(1,980)
All other items – net		54	628	(218)
Net cash provided by operating activities		$ 52,002	$ 49,286	$ 48,138
Cash flows from investing activities				
Additions to property, plant and equipment		$(15,387)	$(15,462)	$(13,839)
Sales of subsidiaries, investments and property, plant and equipment	4	4,204	3,080	6,036
Decrease in restricted cash and cash equivalents	3,15	4,604	—	—
Additional investments and advances		(3,038)	(2,604)	(2,810)
Collection of advances		391	756	343
Additions to marketable securities		(646)	—	—
Sales of marketable securities		144	—	—
Net cash used in investing activities		$ (9,728)	$(14,230)	$(10,270)
Cash flows from financing activities				
Additions to long-term debt		$ 592	$ 318	$ 195
Reductions in long-term debt		(209)	(33)	(81)
Additions to short-term debt		1,211	334	377
Reductions in short-term debt		(809)	(451)	(687)
Additions/(reductions) in debt with less than 90-day maturity		(187)	(95)	(1,306)
Cash dividends to ExxonMobil shareholders		(7,621)	(7,628)	(7,185)
Cash dividends to minority interests		(289)	(239)	(293)
Changes in minority interests and sales/(purchases) of affiliate stock		(659)	(493)	(681)
Tax benefits related to stock-based awards		369	462	—
Common stock acquired		(31,822)	(29,558)	(18,221)
Common stock sold		1,079	1,173	941
Net cash used in financing activities		$(38,345)	$(36,210)	$(26,941)
Effects of exchange rate changes on cash		$ 1,808	$ 727	$ (787)
Increase/(decrease) in cash and cash equivalents		$ 5,737	$ (427)	$ 10,140
Cash and cash equivalents at beginning of year		28,244	28,671	18,531
Cash and cash equivalents at end of year		$ 33,981	$ 28,244	$ 28,671

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

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 2007 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation. The Consolidated Financial Statements include the accounts of those 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.

Amounts representing the Corporation's percentage interest in the underlying net assets of other subsidiaries and less-than-majority-owned companies in which a significant ownership percentage interest is held are included in "Investments, advances and long-term receivables"; 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 prospectively from 2006 by associated amounts with no impact on net income. All operating segments were 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.

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.

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 countries with a history of high inflation (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. The Corporation awards share-based compensation to employees in the form of restricted stock and restricted stock units. Compensation expense is measured by the market price of the restricted shares at the date of grant and is recognized in the income statement over the requisite service period of each award. See note 14, Incentive Program, for further details.

2. Accounting Change for Uncertainty in Income Taxes

Effective January 1, 2007, the Corporation adopted the Financial Accounting Standards Board's (FASB) Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes." FIN 48 is an interpretation of FASB Statement 109, "Accounting for Income Taxes," and prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that the Corporation has taken or expects to take in its income tax returns. Upon the adoption of FIN 48, the Corporation recognized a transition gain of $267 million in shareholders' equity. The gain reflected the recognition of several refund claims, partly offset by increased liability reserves. FIN 48 also resulted in a reclassification of amounts previously reported net on the balance sheet. The balance sheet reclassifications resulted in a $2.4 billion increase to investments, advances and long-term receivables, a $1.0 billion decrease to current liabilities, primarily income taxes payable, and a $3.1 billion increase to other long-term obligations. See note 18, Income, Sales-Based and Other Taxes, for additional disclosures.

3. Miscellaneous Financial Information

Research and development costs totaled $814 million in 2007, $733 million in 2006 and $712 million in 2005.

Net income included aggregate foreign exchange transaction gains of $229 million and $278 million in 2007 and 2006, respectively, and losses of $138 million in 2005.

In 2007, 2006 and 2005, net income included gains of $327 million, $401 million and $215 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 $25.4 billion and $15.9 billion at December 31, 2007, and 2006, respectively.

Crude oil, products and merchandise as of year-end 2007 and 2006 consist of the following:

	2007	2006
	(billions of dollars)	
Petroleum products	$ 3.8	$ 3.8
Crude oil	2.6	2.8
Chemical products	2.1	2.1
Gas/other	0.4	0.3
Total	$ 8.9	$ 9.0

The restriction on approximately $4.6 billion of cash and cash equivalents was released in 2007 following an Alabama Supreme Court judgment in ExxonMobil's favor (see note 15).

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 Downstream assets and investments in 2007 and from the sale of Upstream producing properties in 2006 and 2005. These gains are reported in “Other income” on the Consolidated Statement of Income.

	2007	2006	2005
		(millions of dollars)	
Cash payments for interest	$ 555	$ 1,382	$ 473
Cash payments for income taxes	$26,342	$26,165	$22,535

5. Additional Working Capital Information

	Dec. 31 2007	Dec. 31 2006
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $258 million and $306 million	$30,775	$25,076
Other, less reserves of $36 million and $64 million	5,675	3,866
Total	$36,450	$28,942
Notes and loans payable		
Bank loans	$ 1,238	$ 753
Commercial paper	205	274
Long-term debt due within one year	318	459
Other	622	216
Total	$ 2,383	$ 1,702
Accounts payable and accrued liabilities		
Trade payables	$29,239	$25,084
Payables to equity companies	3,556	2,597
Accrued taxes other than income taxes	6,485	6,052
Other	5,995	5,349
Total	$45,275	$39,082

On December 31, 2007, unused credit lines for short-term financing totaled approximately $5.7 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, 2007, and 2006, was 5.5 percent.

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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, refining, 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 equity company revenues from sales to ExxonMobil consolidated companies was 23 percent, 24 percent and 22 percent in the years 2007, 2006 and 2005, respectively.

	2007		2006		2005	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	$109,149	$ 37,724	$98,542	$ 33,505	$88,003	$ 31,395
Income before income taxes	$ 30,505	$ 11,448	$24,094	$ 8,905	$24,070	$ 9,809
Income taxes	7,557	2,547	5,582	1,920	5,574	2,226
Net income	$ 22,948	$ 8,901	$18,512	$ 6,985	$18,496	$ 7,583
Current assets	$ 29,268	$ 10,228	$24,684	$ 8,484	$24,931	$ 8,645
Property, plant and equipment, less accumulated depreciation	70,591	22,638	59,691	19,602	50,622	17,149
Other long-term assets	6,667	3,092	7,209	4,206	6,900	3,919
Total assets	$106,526	$ 35,958	$91,584	$ 32,292	$82,453	$ 29,713
Short-term debt	$ 3,127	$ 1,117	$ 2,669	$ 888	$ 3,412	$ 1,179
Other current liabilities	20,861	7,124	16,543	5,852	15,330	5,414
Long-term debt	19,821	2,269	16,442	1,920	13,419	2,271
Other long-term liabilities	8,142	3,395	7,946	3,250	7,477	3,153
Advances from shareholders	18,422	8,353	15,791	6,803	14,390	5,580
Net assets	$ 36,153	$ 13,700	$32,193	$ 13,579	$28,425	$ 12,116

A list of significant equity companies as of December 31, 2007, 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
Fujian Refining & Petrochemical Company Ltd.	25
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, Advances and Long-Term Receivables

	Dec. 31 2007	Dec. 31 2006
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	$13,700	$13,579
Advances	8,353	6,803
	$22,053	$20,382
Companies carried at cost or less and stock investments carried at fair value	1,647	1,678
	$23,700	$22,060
Long-term receivables and miscellaneous investments at cost or less	4,494	1,177
Total	$28,194	$23,237

8. Property, Plant and Equipment and Asset Retirement Obligations

	Dec. 31, 2007		Dec. 31, 2006	
Property, Plant and Equipment	**Cost**	**Net**	**Cost**	**Net**
		(millions of dollars)		
Upstream	$ 178,712	$ 73,524	$ 163,087	$ 68,410
Downstream	65,841	30,148	62,392	28,918
Chemical	24,081	10,071	22,197	9,319
Other	11,706	7,126	11,608	7,040
Total	$ 280,340	$ 120,869	$ 259,284	$ 113,687

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 $159,471 million at the end of 2007 and $145,597 million at the end of 2006. Interest capitalized in 2007, 2006 and 2005 was $557 million, $530 million and $434 million, respectively.

Asset Retirement Obligations

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:

	2007	2006
	(millions of dollars)	
Beginning balance	$4,703	$3,568
Accretion expense and other provisions	322	243
Reduction due to property sales	(271)	(202)
Payments made	(352)	(238)
Liabilities incurred	113	263
Revisions	348	832
Foreign currency translation/other	278	237
Ending balance	$5,141	$4,703

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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:

	2007	2006	2005
	(millions of dollars)		
Balance beginning at January 1	$1,305	$1,139	$1,070
Additions pending the determination of proved reserves	228	257	233
Charged to expense	(108)	(54)	(62)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(82)	(22)	(82)
Other	(52)	(15)	(20)
Ending balance	$1,291	$1,305	$1,139
Ending balance attributed to equity companies included above	$ 3	$ 17	$ 2

Period end capitalized suspended exploratory well costs:

	2007	2006	2005
	(millions of dollars)		
Capitalized for a period of one year or less	$ 228	$ 257	$ 233
Capitalized for a period of between one and five years	566	566	485
Capitalized for a period of between five and ten years	255	213	167
Capitalized for a period of greater than ten years	242	269	254
Capitalized for a period greater than one year – subtotal	$1,063	$1,048	$ 906
Total	$1,291	$1,305	$1,139

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.

	2007	2006	2005
Number of projects with first capitalized well drilled in the preceding 12 months	4	13	16
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	49	53	56
Total	53	66	72

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Of the 49 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2007, 29 projects have drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 20 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 20 projects, which total $291 million.

Country/Project	Dec. 31, 2007	Years Wells Drilled	Comment
	(millions of dollars)		
Australia			
– East Pilchard	$9	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
Canada			
– Hibernia	36	2006	Progressing development plan and regulatory approvals for tieback to Hibernia gravity-based structure.
Indonesia			
– 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 2007.
Kazakhstan			
– Aktote	42	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 (4 projects)	12	2001 - 2002	Actively pursuing development of several additional offshore satellite discoveries which will tie back to existing/planned production facilities.
United Kingdom			
– Carrack West	8	2001	Planned tieback to Carrack production facility; awaiting capacity.
– Phyllis	10	2004	Assessing co-development option with nearby 2005 Barbara discovery.
United States			
– Point Thomson	28	1977 - 1980	The Point Thomson Unit owners are progressing plans to put the unit into production. A project team continues evaluating gas transportation alternatives. The 2006 order of the Alaska Department of Natural Resources terminating the Point Thomson Unit was reversed on appeal by order of the Alaska Superior Court.
Other			
– Various (8 projects)	19	1979 - 2005	Projects primarily awaiting capacity in existing or planned infrastructure.
Total – 2007 (20 projects)	$291		

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10. Leased Facilities

At December 31, 2007, 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 $9,916 million as indicated in the table. Estimated related rental income from noncancelable subleases is $191 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	(millions of dollars)	
2008	$ 1,994	$ 37
2009	1,917	32
2010	1,546	28
2011	1,130	24
2012	765	18
2013 and beyond	2,564	52
Total	$ 9,916	$ 191

Net rental expenses under both cancelable and noncancelable operating leases incurred during 2007, 2006 and 2005 were as follows:

	2007	2006	2005
	(millions of dollars)		
Rental expense	$3,367	$3,576	$2,966
Less sublease rental income	168	172	176
Net rental expense	$3,199	$3,404	$2,790

11. Earnings Per Share

	2007	2006	2005
Net income per common share			
Net income *(millions of dollars)*	$40,610	$39,500	$36,130
Weighted average number of common shares outstanding *(millions of shares)*	5,517	5,913	6,266
Net income per common share *(dollars)*	$ 7.36	$ 6.68	$ 5.76
Net income per common share – assuming dilution			
Net income *(millions of dollars)*	$40,610	$39,500	$36,130
Weighted average number of common shares outstanding *(millions of shares)*	5,517	5,913	6,266
Effect of employee stock-based awards	60	57	56
Weighted average number of common shares outstanding – assuming dilution	5,577	5,970	6,322
Net income per common share *(dollars)*	$ 7.28	$ 6.62	$ 5.71
Dividends paid per common share *(dollars)*	$ 1.37	$ 1.28	$ 1.14

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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, 2007, and 2006, was $7.9 billion and $7.2 billion, respectively, as compared to recorded book values of $7.2 billion and $6.6 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 receivable of $31 million at year-end 2007 and a net payable of $64 million at year-end 2006. This is the amount that the Corporation would have received from, or paid to, third parties if these derivatives had been settled in the open market. The Corporation recognized a before-tax gain of $66 million and $397 million and a loss of $312 million related to derivatives during 2007, 2006 and 2005, respectively.

The fair value of derivatives outstanding at year-end 2007 and gain recognized during the year are immaterial in relation to the Corporation's year-end cash balance of $34.0 billion, total assets of $242.1 billion or net income for the year of $40.6 billion.

13. Long-Term Debt

At December 31, 2007, long-term debt consisted of $6,689 million due in U.S. dollars and $494 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 $318 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, 2008, in millions of dollars, are: 2009 – $255, 2010 – $203, 2011 – $206 and 2012 – $2,246. At December 31, 2007, the Corporation's unused long-term credit lines were not material.

Summarized long-term borrowings at year-end 2007 and 2006 were as shown in the table below:

	2007	2006
	(millions of dollars)	
Exxon Capital Corporation		
6.125% Guaranteed notes due 2008	$ —	$ 160
SeaRiver Maritime Financial Holdings, Inc. *(1)*		
Guaranteed debt securities due 2008-2011 *(2)*	39	52
Guaranteed deferred interest debentures due 2012		
– Face value net of unamortized discount plus accrued interest	1,727	1,550
Mobil Services (Bahamas) Ltd.		
Variable notes due 2035 *(3)*	972	972
Variable notes due 2034 *(4)*	311	311
Mobil Producing Nigeria Unlimited *(5)*		
Variable notes due 2012-2016	708	489
Esso (Thailand) Public Company Ltd. *(6)*		
Variable note due 2009-2012	326	—
Mobil Corporation		
8.625% debentures due 2021	248	248
Industrial revenue bonds due 2012-2039 *(7)*	1,694	1,697
Other U.S. dollar obligations *(8)*	629	786
Other foreign currency obligations	120	160
Capitalized lease obligations *(9)*	409	220
Total long-term debt	$ 7,183	$ 6,645

(1) Additional information is provided for this subsidiary on the following pages.
(2) Average effective interest rate of 5.3% in 2007 and 5.1% in 2006.
(3) Average effective interest rate of 5.3% in 2007 and 5.1% in 2006.
(4) Average effective interest rate of 5.4% in 2007 and 5.1% in 2006.
(5) Average effective interest rate of 8.8% in 2007 and 8.6% in 2006.
(6) Average effective interest rate of 4.5% in 2007.
(7) Average effective interest rate of 3.9% in 2007 and 3.7% in 2006.
(8) Average effective interest rate of 6.6% in 2007 and 6.6% in 2006.
(9) Average imputed interest rate of 7.3% in 2007 and 7.6% in 2006.

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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 ($1,727 million long-term debt at December 31, 2007) and the debt securities due 2008 to 2011 ($39 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, 2007					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 16,502	$ —	$ 373,826	$ —	$ 390,328
Income from equity affiliates	40,800	4	8,859	(40,762)	8,901
Other income	488	—	4,835	—	5,323
Intercompany revenue	39,490	101	361,263	(400,854)	—
Total revenues and other income	97,280	105	748,783	(441,616)	404,552
Costs and other deductions					
Crude oil and product purchases	38,260	—	535,973	(374,735)	199,498
Production and manufacturing expenses	7,147	—	30,003	(5,265)	31,885
Selling, general and administrative expenses	2,581	—	13,116	(807)	14,890
Depreciation and depletion	1,661	—	10,589	—	12,250
Exploration expenses, including dry holes	276	—	1,193	—	1,469
Interest expense	5,997	201	14,601	(20,399)	400
Sales-based taxes	—	—	31,728	—	31,728
Other taxes and duties	48	—	40,905	—	40,953
Income applicable to minority and preferred interests	—	—	1,005	—	1,005
Total costs and other deductions	55,970	201	679,113	(401,206)	334,078
Income before income taxes	41,310	(96)	69,670	(40,410)	70,474
Income taxes	700	(34)	29,198	—	29,864
Net income	$ 40,610	$ (62)	$ 40,472	$ (40,410)	$ 40,610

	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
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

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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, 2007					
Cash and cash equivalents	$ 1,393	$ —	$ 32,588	$ —	$ 33,981
Cash and cash equivalents – restricted	—	—	—	—	—
Marketable securities	—	—	519	—	519
Notes and accounts receivable – net	3,733	2	34,338	(1,623)	36,450
Inventories	1,198	—	9,891	—	11,089
Prepaid taxes and expenses	373	—	3,551	—	3,924
Total current assets	6,697	2	80,887	(1,623)	85,963
Investments, advances and long-term receivables	208,062	362	420,262	(600,492)	28,194
Property, plant and equipment – net	16,291	—	104,578	—	120,869
Other long-term assets	221	51	6,784	—	7,056
Intercompany receivables	14,577	1,961	437,433	(453,971)	—
Total assets	$ 245,848	$ 2,376	$1,049,944	$(1,056,086)	$ 242,082
Notes and loans payable	$ 3	$ 13	$ 2,367	$ —	$ 2,383
Accounts payable and accrued liabilities	3,038	1	42,236	—	45,275
Income taxes payable	—	—	12,277	(1,623)	10,654
Total current liabilities	3,041	14	56,880	(1,623)	58,312
Long-term debt	276	1,766	5,141	—	7,183
Deferred income tax liabilities	1,829	212	20,858	—	22,899
Other long-term liabilities	11,308	—	20,618	—	31,926
Intercompany payables	107,632	382	345,957	(453,971)	—
Total liabilities	124,086	2,374	449,454	(455,594)	120,320
Earnings reinvested	228,518	(467)	114,037	(113,570)	228,518
Other shareholders’ equity	(106,756)	469	486,453	(486,922)	(106,756)
Total shareholders’ equity	121,762	2	600,490	(600,492)	121,762
Total liabilities and shareholders’ equity	$ 245,848	$ 2,376	$1,049,944	$(1,056,086)	$ 242,082
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, advances and long-term receivables	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

	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, 2007					
Cash provided by/(used in) operating activities	$ 73,813	$ 97	$ 49,185	$ (71,093)	$ 52,002
Cash flows from investing activities					
Additions to property, plant and equipment	(1,252)	—	(14,135)	—	(15,387)
Sales of long-term assets	251	—	3,953	—	4,204
Decrease/(increase) in restricted cash and cash equivalents	—	—	4,604	—	4,604
Net intercompany investing	(39,679)	(79)	39,676	82	—
All other investing, net	—	—	(3,149)	—	(3,149)
Net cash provided by/(used in) investing activities	(40,680)	(79)	30,949	82	(9,728)
Cash flows from financing activities					
Additions to short- and long-term debt	—	—	1,803	—	1,803
Reductions in short- and long-term debt	(3)	(13)	(1,002)	—	(1,018)
Additions/(reductions) in debt with less than 90-day maturity	(97)	—	(90)	—	(187)
Cash dividends	(7,621)	—	(71,093)	71,093	(7,621)
Common stock acquired	(31,822)	—	—	—	(31,822)
Net intercompany financing activity	—	(5)	87	(82)	—
All other financing, net	1,448	—	(948)	—	500
Net cash provided by/(used in) financing activities	(38,095)	(18)	(71,243)	71,011	(38,345)
Effects of exchange rate changes on cash	—	—	1,808	—	1,808
Increase/(decrease) in cash and cash equivalents	$ (4,962)	$ —	$ 10,699	$ —	$ 5,737
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)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 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

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 2007, remaining shares available for award under the 2003 Incentive Program were 170,695 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 10,226 thousand, 10,187 thousand and 11,071 thousand shares of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2007, 2006 and 2005, 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.

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, 2007.

Restricted Stock and Units Outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	
Issued and outstanding at January 1, 2007	36,124	$ 47.30
2006 award issued in 2007	10,167	$ 73.47
Vested	(6,795)	$ 46.02
Forfeited	(281)	$ 53.57
Issued and outstanding at December 31, 2007	39,215	$ 54.26

Grant Value of Restricted Stock and Units	**2007**	**2006**	**2005**
Grant price	$87.14	$73.47	$58.43
		(millions of dollars)	
Value at date of grant:			
Restricted stock and units settled in stock	$ 827	$ 704	$ 611
Units settled in cash	64	44	36
Total value	$ 891	$ 748	$ 647

As of December 31, 2007, there was $1,892 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 $590 million, $527 million and $387 million for 2007, 2006 and 2005, respectively. The income tax benefit recognized in income related to this compensation expense was $81 million, $72 million and $69 million for the same periods, respectively. The fair value of shares and units vested in 2007, 2006 and 2005 was $581 million, $310 million and $288 million, respectively. Cash payments of $29 million, $18 million and $15 million for vested restricted stock units settled in cash were made in 2007, 2006 and 2005, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Changes that occurred in stock options in 2007 are summarized below (shares in thousands):

Stock Options	2007 Shares	2007 Avg. Exercise Price	Weighted Average Remaining Contractual Term
Outstanding at January 1	110,487	$ 38.86	
Exercised	(30,168)	$ 35.88	
Forfeited	(30)	$ 37.11	
Outstanding at December 31	80,289	$ 39.98	2.7 Years
Exercisable at December 31	80,289	$ 39.98	2.7 Years

No compensation expense was recognized for stock options in 2007, 2006 and 2005, as all remaining outstanding stock options were granted prior to 2002 and are fully vested. Cash received from stock option exercises was $1,079 million, $1,173 million and $941 million for 2007, 2006 and 2005, respectively. The cash tax benefit realized for the options exercised was $304 million, $416 million and $295 million for 2007, 2006 and 2005, respectively. The aggregate intrinsic value of stock options exercised in 2007, 2006 and 2005 was $1,359 million, $1,304 million and $954 million, respectively. The intrinsic value for the balance of outstanding stock options at December 31, 2007, was $4,312 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. Management has regular litigation 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. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. 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. On May 23, 2007, with two dissenting opinions, the Ninth Circuit determined not to re-hear ExxonMobil’s appeal before the full court. ExxonMobil filed a petition for writ of certiorari to the U.S. Supreme Court on August 20, 2007. On October 29, 2007, the U.S. Supreme Court granted ExxonMobil’s petition for a writ of certiorari. Oral argument was held on February 27, 2008. 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 appealed the decision to the Alabama Supreme Court. On November 1, 2007, the Alabama Supreme Court reversed the trial court’s fraud judgment and instructed the district court to enter judgment for ExxonMobil on the fraud claim, eliminating the punitive damage award. The Court also ruled in ExxonMobil’s favor on some of the disputed lease issues, reducing the compensatory award to $52 million plus interest. Following the Alabama Supreme Court’s decision, an appeal bond was canceled and the collateral was subsequently released.

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*. On August 8, 2007, the Fourth Circuit issued its decision on remand and declined to reduce the punitive damage award. On November 16, 2007, the Louisiana Supreme Court denied ExxonMobil's writ for review of the Fourth Circuit's decision. ExxonMobil has appealed to the U.S. Supreme Court.

Other Contingencies

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2007, for $5,148 million, primarily relating to guarantees for notes, loans and performance under contracts. Included in this amount were guarantees by consolidated affiliates of $4,591 million, representing ExxonMobil's share of obligations of certain equity companies.

	Dec. 31, 2007		
	Equity Company Obligations	Other Third-Party Obligations	Total
	(millions of dollars)		
Total guarantees	$ 4,591	$ 557	$5,148

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

	Payments Due by Period			
	2008	2009-2012	2013 and Beyond	Total
	(millions of dollars)			
Unconditional purchase obligations *(1)*	$490	$1,497	$ 778	$2,765

(1) Undiscounted obligations of $2,765 million mainly pertain to pipeline throughput agreements and include $1,847 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of $562 million, totaled $2,203 million.

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and owned by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulation that if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assume the activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by PdVSA, and on June 27, 2007, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project.

To date, discussions with Venezuelan authorities have not resulted in an agreement on the amount of compensation to be paid to ExxonMobil. On September 6, 2007, ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes. ExxonMobil has also filed an arbitration under the rules of the International Chamber of Commerce against PdVSA and a PdVSA affiliate for breach of their contractual obligations under certain Cerro Negro Project agreements. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition. At the time the assets were expropriated, ExxonMobil's remaining net book investment in Cerro Negro producing assets was about $750 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.			
	2007	2006	2007	2006	2007	2006
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	6.25	6.00	5.40	4.70	6.25	6.00
Long-term rate of compensation increase	5.00	4.50	4.50	4.20	5.00	4.50
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	$11,305	$11,181	$20,956	$19,310	$ 6,843	$ 5,370
Service cost	360	335	451	428	109	76
Interest cost	687	632	1,011	911	403	308
Actuarial loss/(gain)	896	484	(665)	(38)	(275)	1,440
Benefits paid *(1) (2)*	(1,091)	(1,329)	(1,197)	(1,153)	(416)	(419)
Foreign exchange rate changes	—	—	1,937	1,424	73	—
Plan amendments, other	(95)	2	(18)	74	91	68
Benefit obligation at December 31	$12,062	$11,305	$22,475	$20,956	$ 6,828	$ 6,843
Accumulated benefit obligation at December 31	$10,244	$ 9,811	$20,151	$18,883	$ —	$ —

(1) Benefit payments for funded and unfunded plans.
(2) For 2007 and 2006, other postretirement benefits paid are net of $19 million and $20 million Medicare subsidy receipts, respectively.

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 2008 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 $54 million and the postretirement benefit obligation by $564 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $44 million and the post-retirement benefit obligation by $468 million.

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.			
	2007	2006	2007	2006	2007	2006
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	$ 9,752	$ 7,250	$14,387	$12,063	$ 501	$ 456
Actual return on plan assets	970	1,207	761	1,669	23	66
Foreign exchange rate changes	—	—	1,284	891	—	—
Company contribution	800	2,383	1,666	724	191	34
Benefits paid *(1)*	(905)	(1,088)	(816)	(796)	(56)	(55)
Other	—	—	(90)	(164)	—	—
Fair value at December 31	$10,617	$ 9,752	$17,192	$14,387	$ 659	$ 501

(1) Benefit payments for funded plans.

The funding levels of all qualified pension plans are in compliance with standards set by applicable law or regulation. As shown in the table below, certain smaller U.S. pension plans and a number of non-U.S. pension 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.

In 2007 and 2006, the Corporation contributed $800 million and $2,383 million, respectively, to the U.S. funded pension plan, approximately the maximum tax-deductible amount. As a result, year-end 2007 U.S. pension assets of $10,617 million were $1,493 million greater than the funded plan accumulated benefit obligation of $9,124 million.

	Pension Benefits			
	U.S.		Non-U.S.	
	2007	2006	2007	2006
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	$ (64)	$ (254)	$ 192	$(1,479)
Unfunded plans	(1,381)	(1,299)	(5,475)	(5,090)
Total	$(1,445)	$(1,553)	$(5,283)	$(6,569)

Effective December 31, 2006, Exxon Mobil Corporation implemented FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," 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 comprehensive income.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2007	2006	2007	2006	2007	2006
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	$(1,445)	$(1,553)	$(5,283)	$(6,569)	$(6,169)	$ (6,342)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	$ 43	$ 36	$ 1,168	$ 196	$ —	$ —
Current liabilities	(177)	(160)	(329)	(294)	(324)	(311)
Postretirement benefits reserves	(1,311)	(1,429)	(6,122)	(6,471)	(5,845)	(6,031)
Total recorded	$(1,445)	$(1,553)	$(5,283)	$(6,569)	$(6,169)	$ (6,342)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	$ 2,378	$ 2,044	$ 3,520	$ 3,838	$ 2,346	$ 2,831
Prior service cost	3	121	810	780	326	401
Total recorded in accumulated other comprehensive income	$ 2,381	$ 2,165	$ 4,330	$ 4,618	$ 2,672	$ 3,232

(1) Fair value of assets less benefit obligation shown on the preceding page.

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	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2007	2006	2005	2007	2006	2005	2007	2006	2005
					(percent)				
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31									
Discount rate	6.00	5.75	5.75	4.70	4.50	4.90	6.00	5.75	5.75
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	4.50	4.50	4.50	4.20	3.90	3.80	4.50	4.50	4.50
					(millions of dollars)				
Components of net periodic benefit cost									
Service cost	$ 360	$ 335	$ 330	$ 451	$ 428	$ 382	$ 109	$ 76	$ 70
Interest cost	687	632	611	1,011	911	834	403	308	301
Expected return on plan assets	(844)	(620)	(629)	(1,105)	(982)	(789)	(44)	(41)	(39)
Amortization of actuarial loss/(gain)	246	249	247	362	434	360	243	145	131
Amortization of prior service cost	23	24	27	89	79	64	75	73	73
Net pension enhancement and curtailment/settlement expense	190	157	123	19	47	10	9	—	—
Net periodic benefit cost	$ 662	$ 777	$ 709	$ 827	$ 917	$ 861	$ 795	$ 561	$ 536
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	$ 770	$1,265	$(196)	$ (294)	$ 914	$ (74)	$(245)	$2,831	$ —
Amortization of actuarial (loss)/gain	(436)	—	—	(381)	—	—	(252)	—	—
Prior service cost/(credit)	(95)	121	—	72	780	—	—	401	—
Amortization of prior service (cost)	(23)	—	—	(89)	—	—	(75)	—	—
Foreign exchange rate changes	—	—	—	404	—	—	12	—	—
Total recorded in accumulated other comprehensive income	216	1,386	(196)	(288)	1,694	(74)	(560)	3,232	—
Total recorded in net periodic benefit cost and accumulated other comprehensive income, before tax	$ 878	$2,163	$ 513	$ 539	$2,611	$ 787	$ 235	$3,793	$ 536

Costs for defined contribution plans were $287 million, $260 million and $251 million in 2007, 2006 and 2005, respectively.

A summary of the change in accumulated other comprehensive income is shown in the table below:

	Total Pension and Other Postretirement Benefits		
	2007	2006	2005
		(millions of dollars)	
(Charge)/credit to accumulated other comprehensive income, before tax			
U.S. pension	$ (216)	$ (1,386)	$ 196
Non-U.S. pension	288	(1,694)	74
Other postretirement benefits	560	(3,232)	—
Total (charge)/credit to accumulated other comprehensive income, before tax	632	(6,312)	270
(Charge)/credit to income tax (see note 18)	(207)	2,105	(90)
Charge/(credit) to equity of minority shareholders	61	38	61
(Charge)/credit to investment in equity companies	26	(68)	—
(Charge)/credit to accumulated other comprehensive income, after tax	$ 512	$ (4,237)	$ 241

The long-term expected rate of return on funded assets for each plan is established 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. The majority of pension assets are invested in equities, as illustrated in the table below, which shows asset allocation.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2007	2006	2007	2006	2007	2006
	(percent)					
Funded benefit plan asset allocation						
Equity securities	75%	75%	65%	69%	75%	75%
Debt securities	25	25	30	27	25	25
Other	—	—	5	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 64 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.	
	2007	2006	2007	2006
	(millions of dollars)			
For funded pension plans with accumulated benefit obligations in excess of plan assets:				
Projected benefit obligation	$ —	$ 4	$2,697	$8,971
Accumulated benefit obligation	—	3	2,527	8,322
Fair value of plan assets	—	2	1,919	7,265
For unfunded pension plans:				
Projected benefit obligation	$1,381	$1,299	$5,475	$5,090
Accumulated benefit obligation	1,120	1,120	4,827	4,502

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2008 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	$382	$ 311	$ 203
Prior service cost *(2)*	(2)	97	76

(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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
		(millions of dollars)		
Contributions expected in 2008	$ —	$ 529	$ —	$ —
Benefit payments expected in:				
2008	962	1,244	415	23
2009	1,014	1,227	437	24
2010	1,058	1,274	460	26
2011	1,089	1,286	482	27
2012	1,140	1,338	499	29
2013 - 2017	5,741	7,615	2,709	169

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 (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) 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 (3) for which discrete financial information is available.

Earnings after income tax include special items, and transfers are at estimated market prices. There were no special items in 2007. After-tax earnings in 2006 included 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.

Interest expense includes non-debt-related interest expense of $290 million, $535 million and $369 million in 2007, 2006 and 2005, respectively. The decrease of $245 million in 2007 and the increase of $166 million in 2006 primarily reflect changes in tax-related interest.

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

	Upstream		Downstream		Chemical		Corporate and Financing	Corporate Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.		
				(millions of dollars)				
As of December 31, 2007								
Earnings after income tax	$ 4,870	$21,627	$ 4,120	$ 5,453	$ 1,181	$ 3,382	$ (23)	$ 40,610
Earnings of equity companies included above	1,455	5,393	208	641	120	1,558	(474)	8,901
Sales and other operating revenue *(1)*	5,661	22,995	101,671	223,145	13,790	23,036	30	390,328
Intersegment revenue	7,596	47,498	13,942	52,403	8,710	7,881	303	—
Depreciation and depletion expense	1,469	7,126	639	1,662	405	418	531	12,250
Interest revenue	—	—	—	—	—	—	1,672	1,672
Interest expense	57	75	14	26	2	2	224	400
Income taxes	2,686	23,328	2,141	1,405	392	591	(679)	29,864
Additions to property, plant and equipment	1,595	9,139	1,061	1,578	335	1,078	601	15,387
Investments in equity companies	2,016	7,194	488	1,172	224	2,650	(44)	13,700
Total assets	21,782	84,440	18,569	54,883	7,617	13,801	40,990	242,082
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

Geographic Sales and other operating revenue *(1)*	**2007**	**2006**	**2005**
		(millions of dollars)	
United States	$ 121,144	$ 112,787	$ 110,553
Non-U.S.	269,184	252,680	248,402
Total	$ 390,328	$ 365,467	$ 358,955
Significant non-U.S. revenue sources include:			
Canada	$ 27,284	$ 25,281	$ 28,842
Japan	26,146	27,368	28,963
United Kingdom	25,113	24,646	24,805
Belgium	20,550	16,271	11,281
Germany	17,445	19,458	21,653
Italy	16,255	15,332	17,160
France	14,287	13,537	14,412

(1) *Sales and other operating revenue includes sales-based taxes of $31,728 million for 2007, $30,381 million for 2006 and $30,742 million for 2005. Includes $30,810 million for purchases/sales contracts with the same counterparty for 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	**2007**	**2006**	**2005**
		(millions of dollars)	
United States	$ 33,630	$ 33,233	$ 33,117
Non-U.S.	87,239	80,454	73,893

Total	$ 120,869	$ 113,687	$ 107,010
Significant non-U.S. long-lived assets include:			
Canada	$ 14,167	$ 12,323	$ 12,273
United Kingdom	8,589	9,128	7,757
Norway	7,920	6,977	6,472
Nigeria	7,504	7,350	6,409
Angola	5,084	4,271	3,803
Japan	4,077	4,008	4,016
Singapore	3,598	2,964	2,968
Australia	3,331	2,966	2,717

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

18. Income, Sales-Based and Other Taxes

	2007			2006			2005		
	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	$ 4,666	$24,329	$ 28,995	$ 2,851	$22,666	$ 25,517	$ 5,462	$17,052	$22,514
Deferred – net	(439)	415	(24)	1,194	165	1,359	(584)	362	(222)
U.S. tax on non-U.S. operations	263	—	263	239	—	239	208	—	208
Total federal and non-U.S.	4,490	24,744	29,234	4,284	22,831	27,115	5,086	17,414	22,500
State	630	—	630	787	—	787	802	—	802
Total income taxes	5,120	24,744	29,864	5,071	22,831	27,902	5,888	17,414	23,302
Sales-based taxes	7,154	24,574	31,728	7,100	23,281	30,381	7,072	23,670	30,742
All other taxes and duties									
Other taxes and duties	1,008	39,945	40,953	392	38,811	39,203	51	41,503	41,554
Included in production and manufacturing expenses	825	1,445	2,270	976	1,431	2,407	1,182	1,075	2,257
Included in SG&A expenses	215	653	868	211	572	783	202	558	760
Total other taxes and duties	2,048	42,043	44,091	1,579	40,814	42,393	1,435	43,136	44,571
Total	$14,322	$91,361	$105,683	$13,750	$86,926	$100,676	$14,395	$84,220	$98,615

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 $258 million in 2007, $169 million in 2006 and $199 million in 2005.

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

	2007	2006	2005
		(millions of dollars)	
Cumulative foreign exchange translation adjustment	$(269)	$ (36)	$158
Postretirement benefits reserves adjustment:			
Net actuarial loss/(gain)	102		
Amortization of actuarial loss/(gain)	(358)		
Prior service cost	(23)		
Amortization of prior service cost	(60)		
Foreign exchange rate changes	132		
Total postretirement benefits reserves adjustment	(207)	3,372	—
Minimum pension liability adjustment	—	(1,267)	(90)
Gains and losses on stock investments	—	—	236
Other components of shareholders' equity	113	169	224

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2007, 2006 and 2005, is as follows:

	2007	2006	2005
		(millions of dollars)	
Income before income taxes			
United States	$13,700	$15,507	$16,900
Non-U.S.	56,774	51,895	42,532
Total	$70,474	$67,402	$59,432
Theoretical tax	$24,666	$23,591	$20,801
Effect of equity method of accounting	(3,115)	(2,445)	(2,654)
Non-U.S. taxes in excess of theoretical U.S. tax	7,364	6,541	4,719
U.S. tax on non-U.S. operations	263	239	208
State taxes, net of federal tax benefit	410	512	522
Other U.S.	276	(536)	(294)
Total income tax expense	$29,864	$27,902	$23,302

Effective tax rate calculation			
Income taxes	$29,864	$27,902	$23,302
ExxonMobil share of equity company income taxes	2,547	1,920	2,226
Total income taxes	32,411	29,822	25,528
Income from continuing operations	40,610	39,500	36,130
Total income before taxes	$73,021	$69,322	$61,658
Effective income tax rate	44%	43%	41%

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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:	**2007**	**2006**
	(millions of dollars)	
Depreciation	$ 18,810	$ 17,518
Intangible development costs	4,890	4,742
Capitalized interest	2,575	2,499
Other liabilities	3,955	3,240
Total deferred tax liabilities	$ 30,230	$ 27,999
Pension and other postretirement benefits	$ (3,837)	$ (4,135)
Tax loss carryforwards	(2,162)	(2,002)
Other assets	(5,848)	(4,894)
Total deferred tax assets	$(11,847)	$(11,031)
Asset valuation allowances	637	657
Net deferred tax liabilities	$ 19,020	$ 17,625

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	**2007**	**2006**
	(millions of dollars)	
Prepaid taxes and expenses	$ (2,497)	$ (1,636)
Other assets, including intangibles, net	(1,451)	(1,656)
Accounts payable and accrued liabilities	69	66
Deferred income tax liabilities	22,899	20,851
Net deferred tax liabilities	$19,020	$17,625

The Corporation had $56 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.

Unrecognized Tax Benefits

The Corporation is subject to income taxation in many jurisdictions around the world. The total amounts of unrecognized tax benefits at January 1, 2007, and December 31, 2007, are shown in the following table. Resolution of the related tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. Accordingly, it is difficult to predict the timing of resolution for individual tax positions. However, the Corporation does not anticipate that the total amount of unrecognized tax benefits will significantly increase or decrease in the next 12 months. Given the long time periods involved in resolving individual tax positions, the Corporation does not expect that the recognition of unrecognized tax benefits will have a material impact on the Corporation's effective income tax rate in any given year.

The following table summarizes the movement in uncertain tax benefits from January 1 to December 31, 2007. The unrecognized tax benefits are shown on both a gross basis and a net basis, reflecting the impact of funds placed on deposit with tax authorities. Such deposits do not acknowledge agreement with the tax authorities' positions, but prevent further interest accretion on potential tax assessments. For balance sheet reporting, the Corporation reports unrecognized tax benefits net of such deposits where there is a legal right and intent to offset under the local tax law.

	Gross Unrecognized Tax Benefits	**Deposits**	**Net Unrecognized Tax Benefits**
		(millions of dollars)	
January 1, 2007, balance	$ 4,583	$ (879)	$ 3,704
Additions based on current year tax positions	832		832
Additions for prior years' tax positions	463		463
Reductions for prior years' tax positions	(609)		(609)
Reductions due to a lapse of the statute of limitations	(84)		(84)
Settlements with tax authorities	(25)		(25)
Foreign exchange effects/change in deposit balance	72	109	181
December 31, 2007, balance	$ 5,232	$ (770)	$ 4,462

The additions and reductions in unrecognized tax benefits shown above include effects related to net income and shareholders' equity, and timing differences for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. The 2007 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income or cash flow.

The following table summarizes the tax years that remain subject to examination by major tax jurisdiction:

Country of Operation	Open Tax Years
Abu Dhabi	2000 - 2007
Angola	2002 - 2007
Australia	2000 - 2007
Canada	1990 - 2007
Equatorial Guinea	2004 - 2007
Germany	1998 - 2007
Japan	2002 - 2007
Malaysia	1983 - 2007
Nigeria	1998 - 2007
Norway	1993 - 2007
United Kingdom	2003 - 2007
United States	1989 - 2007

The Corporation classifies interest on income tax-related balances as interest expense or interest income and classifies tax-related penalties as operating expense.

The Corporation incurred approximately $128 million in interest expense on income tax reserves in 2007 and had a related interest payable of $597 million at December 31, 2007.

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 $2,271 million in 2007, $2,431 million in 2006 and $3,546 million in 2005.

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Total
				(millions of dollars)			
2007 – Revenue							
Sales to third parties	$ 3,677	$ 3,720	$ 7,282	$ 807	$ 3,363	$ 678	$19,527
Transfers	6,554	2,783	9,780	17,048	7,276	2,087	45,528
	$10,231	$ 6,503	$17,062	$17,855	$ 10,639	$2,765	$65,055
Production costs excluding taxes	1,827	1,492	2,859	1,180	961	243	8,562
Exploration expenses	280	264	164	470	226	67	1,471
Depreciation and depletion	1,377	1,121	2,441	2,101	763	453	8,256
Taxes other than income	1,313	111	718	1,599	2,067	1	5,809
Related income tax	2,429	1,041	7,236	7,263	4,105	598	22,672
Results of producing activities for consolidated subsidiaries	$ 3,005	$ 2,474	$ 3,644	$ 5,242	$ 2,517	$1,403	$18,285
Proportional interest in results of producing activities of equity companies	$ 1,342	$ —	$ 1,465	$ —	$ 2,138	$ 996	$ 5,941
2006 – Revenue							
Sales to third parties	$ 4,027	$ 4,390	$ 9,382	$ 1,145	$ 4,393	$ 533	$23,870
Transfers	6,250	2,638	8,607	16,108	4,900	580	39,083
	$10,277	$ 7,028	$17,989	$17,253	$ 9,293	$1,113	$62,953
Production costs excluding taxes	1,916	1,410	2,290	965	824	118	7,523
Exploration expenses	245	172	161	330	157	116	1,181
Depreciation and depletion	1,155	1,023	2,166	2,096	674	305	7,419
Taxes other than income	802	139	846	1,612	2,652	1	6,052
Related income tax	2,711	1,143	8,032	6,878	2,820	217	21,801
Results of producing activities for consolidated subsidiaries	$ 3,448	$ 3,141	$ 4,494	$ 5,372	$ 2,166	$ 356	$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	$ 3,728	$ 8,383	$ 40	$ 2,357	$ 357	$19,707
Transfers	6,277	3,582	7,040	12,293	3,143	279	32,614
	$11,119	$ 7,310	$15,423	$12,333	$ 5,500	$ 636	$52,321
Production costs excluding taxes	1,367	1,370	2,174	840	567	123	6,441
Exploration expenses	158	137	64	310	122	164	955
Depreciation and depletion	1,181	1,041	2,133	1,319	666	137	6,477
Taxes other than income	738	56	690	1,158	839	2	3,483
Related income tax	3,138	1,641	6,572	5,143	1,313	111	17,918
Results of producing activities for consolidated subsidiaries	$ 4,537	$ 3,065	$ 3,790	$ 3,563	$ 1,993	$ 99	$17,047
Proportional interest in results of producing activities of equity companies	$ 1,043	$ —	$ 1,003	$ —	$ 1,009	$ 701	$ 3,756

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/ South America**	**Europe**	**Africa**	**Asia Pacific/ Middle East**	**Russia/ Caspian**	**Total**
During 2007							
Average sales prices							
Crude oil and NGL, per barrel	$62.35	$ 50.41	$68.01	$70.00	$ 69.58	$69.15	$66.02
Natural gas, per thousand cubic feet	5.93	5.77	6.22	2.26	3.54	1.79	5.29
Average production costs, per barrel *(1)*	9.03	10.38	9.12	4.48	4.09	5.79	7.14
During 2006							
Average sales prices							
Crude oil and NGL, per barrel	$55.13	$ 47.70	$59.90	$61.26	$ 62.02	$57.38	$58.34
Natural gas, per thousand cubic feet	6.22	5.81	7.48	—	3.87	2.31	6.08
Average production costs, per barrel *(1)*	8.78	8.55	6.64	3.39	3.90	5.45	6.04
During 2005							
Average sales prices							
Crude oil and NGL, per barrel	$46.11	$ 38.68	$50.32	$51.21	$ 52.89	$51.65	$48.23
Natural gas, per thousand cubic feet	7.30	6.90	5.64	—	4.16	1.35	5.96
Average production costs, per barrel *(1)*	5.56	7.36	5.95	3.46	3.85	9.49	5.36

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

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

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $6,381 million less at year-end 2007 and $5,463 million less at year-end 2006 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/ South America	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Total
				(millions of dollars)			
As of December 31, 2007							
Property (acreage) costs – Proved	$ 3,227	$ 4,102	$ 272	$ 200	$ 1,172	$ 521	$ 9,494
– Unproved	556	524	30	540	1,142	45	2,837
Total property costs	$ 3,783	$ 4,626	$ 302	$ 740	$ 2,314	$ 566	$ 12,331
Producing assets	35,830	15,370	48,673	19,633	17,302	2,796	139,604
Support facilities	694	269	619	461	1,186	428	3,657
Incomplete construction	2,406	950	891	3,576	3,133	3,040	13,996
Total capitalized costs	$42,713	$ 21,215	$50,485	$24,410	$ 23,935	$6,830	$169,588
Accumulated depreciation and depletion	27,427	13,529	36,520	9,261	14,674	1,034	102,445
Net capitalized costs for consolidated subsidiaries	$15,286	$ 7,686	$13,965	$15,149	$ 9,261	$5,796	$ 67,143
Proportional interest of net capitalized costs of equity companies	$ 1,662	$ —	$ 1,461	$ —	$ 1,413	$3,346	$ 7,882
As of December 31, 2006							
Property (acreage) costs – Proved	$ 3,260	$ 3,532	$ 277	$ 200	$ 1,164	$ 512	$ 8,945
– Unproved	574	429	31	523	1,070	99	2,726
Total property costs	$ 3,834	$ 3,961	$ 308	$ 723	$ 2,234	$ 611	$ 11,671
Producing assets	34,852	12,800	44,719	16,748	16,295	2,324	127,738
Support facilities	740	257	581	442	1,158	308	3,486
Incomplete construction	2,273	893	1,439	3,533	1,537	2,605	12,280
Total capitalized costs	$41,699	$ 17,911	$47,047	$21,446	$ 21,224	$5,848	$155,175
Accumulated depreciation and depletion	26,696	10,780	33,302	7,166	13,649	635	92,228
Net capitalized costs for consolidated subsidiaries	$15,003	$ 7,131	$13,745	$14,280	$ 7,575	$5,213	$ 62,947
Proportional interest of net capitalized costs of equity companies	$ 1,527	$ —	$ 1,437	$ —	$ 1,238	$3,033	$ 7,235

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 2007 were $12,075 million, down $938 million from 2006, due primarily to lower development and property acquisition costs. 2006 costs were $13,013 million, up $2,229 million from 2005, due primarily to higher development and property acquisition costs.

Costs incurred in property acquisitions, exploration and development activities	**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia Pacific/ Middle East**	**Russia/ Caspian**	**Total**
				(millions of dollars)			
During 2007							
Property acquisition costs – Proved	$ 24	$ —	$ —	$ 3	$ —	$ 10	$ 37
– Unproved	39	93	—	10	15	—	157
Exploration costs	375	222	201	584	261	80	1,723
Development costs	1,558	645	1,826	2,846	2,156	1,127	10,158
Total costs incurred for consolidated subsidiaries	$1,996	$ 960	$2,027	$3,443	$ 2,432	$1,217	$ 12,075
Proportional interest of costs incurred of equity companies	$ 303	$ —	$ 218	$ 1	$ 249	$ 414	$ 1,185
During 2006							
Property acquisition costs – Proved	$ 11	$ —	$ 6	$ —	$ 206	$ 11	$ 234
– Unproved	43	—	5	16	199	—	263
Exploration costs	380	225	178	518	219	126	1,646
Development costs	1,555	850	2,443	3,433	1,475	1,114	10,870
Total costs incurred for consolidated subsidiaries	$1,989	$ 1,075	$2,632	$3,967	$ 2,099	$1,251	$ 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	18	—	53	41	156	279
Exploration costs	286	121	133	507	171	159	1,377
Development costs	1,426	722	1,302	3,189	541	1,774	8,954
Total costs incurred for consolidated subsidiaries	$1,723	$ 861	$1,435	$3,749	$ 753	$2,263	$ 10,784
Proportional interest of costs incurred of equity companies	$ 269	$ —	$ 210	$ —	$ 319	$ 384	$ 1,182

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

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2005, 2006 and 2007.

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.

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. We understand that the use of December 31 prices and costs is intended to provide a point in time measure to calculate reserves and to enhance comparability between companies.

Regulations preclude the Corporation from showing in this document, however, 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 2007 that were associated with production sharing contract arrangements was 18 percent of liquids, 13 percent of natural gas and 15 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.

Crude Oil and Natural Gas Liquids	United States	Canada/ South America *(1)*	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Total
				(millions of barrels)			
Net proved developed and undeveloped reserves of consolidated subsidiaries							
January 1, 2005	2,593	1,105	1,014	2,444	515	724	8,395
Revisions	(256)	336	17	(8)	78	(27)	140
Purchases	—	—	—	—	—	93	93
Sales	(96)	(49)	(1)	—	(11)	(70)	(227)
Improved recovery	2	—	3	—	—	—	5
Extensions and discoveries	6	16	47	120	—	—	189
Production	(136)	(125)	(197)	(244)	(67)	(13)	(782)
December 31, 2005	2,113	1,283	883	2,312	515	707	7,813
Revisions	(99)	247	50	24	19	105	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)	(108)	(188)	(285)	(114)	(21)	(832)
December 31, 2006	1,884	1,395	748	2,089	1,287	791	8,194
Revisions	76	15	89	99	342	(38)	583
Purchases	—	—	—	—	—	—	—
Sales	(8)	(426)[(2)]	(1)	—	—	—	(435)
Improved recovery	8	5	8	4	—	—	25
Extensions and discoveries	2	45	2	128	1	—	178
Production	(111)	(95)	(173)	(262)	(120)	(40)	(801)
December 31, 2007	1,851	939	673	2,058	1,510	713	7,744
Proportional interest in proved reserves of equity companies							
End of year 2005	413	—	11	—	1,381	873	2,678
End of year 2006	391	—	12	—	1,412	841	2,656
End of year 2007	374	—	26	—	1,428	808	2,636
Proved developed reserves, included above, as of December 31, 2005							
Consolidated subsidiaries	1,680	834	656	1,218	464	55	4,907
Equity companies	326	—	9	—	725	574	1,634
Proved developed reserves, included above, as of December 31, 2006							
Consolidated subsidiaries	1,466	902	557	1,279	1,090	108	5,402
Equity companies	311	—	11	—	630	544	1,496
Proved developed reserves, included above, as of December 31, 2007							
Consolidated subsidiaries	1,327	682	518	1,202	1,127	91	4,947
Equity companies	299	—	8	—	670	511	1,488

(1) Includes total proved reserves attributable to Imperial Oil Limited of 634 million barrels in 2005, 812 million barrels in 2006 and 799 million barrels in 2007, as well as proved developed reserves of 449 million barrels in 2005, 572 million barrels in 2006 and 565 million barrels in 2007, in which there is a 30.4 percent minority interest.

(2) Includes 425 million barrels of proved reserves in Venezuela which were expropriated. See note 15, Litigation and Other Contingencies.

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

Oil and Gas Reserves *(continued)*

Natural Gas	United States	Canada/ South America *(1)*	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Total
			(billions of cubic feet)				
Net proved developed and undeveloped reserves of consolidated subsidiaries							
January 1, 2005	12,329	2,652	9,185	771	6,391	515	31,843
Revisions	1,943	83	242	35	1,402	(18)	3,687
Purchases	—	—	—	—	—	53	53
Sales	(105)	(25)	(73)	—	—	(26)	(229)
Improved recovery	—	—	—	—	—	—	—
Extensions and discoveries	289	26	116	57	32	300	820
Production	(764)	(412)	(1,072)	(22)	(546)	(3)	(2,819)
December 31, 2005	13,692	2,324	8,398	841	7,279	821	33,355
Revisions	(1,179)	73	(457)	170	414	(20)	(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)	(379)	(1,004)	(26)	(644)	(12)	(2,771)
December 31, 2006	12,049	1,984	7,089	986	9,583	789	32,480
Revisions	1,566	124	375	(22)	813	(43)	2,813
Purchases	9	—	—	—	—	—	9
Sales	(19)	(231)[(2)]	(70)	—	—	—	(320)
Improved recovery	—	1	—	—	—	—	1
Extensions and discoveries	208	8	13	81	—	—	310
Production	(641)	(327)	(895)	(39)	(762)	(19)	(2,683)
December 31, 2007	13,172	1,559	6,512	1,006	9,634	727	32,610
Proportional interest in proved reserves of equity companies							
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
End of year 2007	125	—	12,341	—	21,733	1,453	35,652

(1) *Includes total proved reserves attributable to Imperial Oil Limited of 747 billion cubic feet in 2005, 710 billion cubic feet in 2006 and 635 billion cubic feet in 2007, in which there is a 30.4 percent minority interest.*

(2) *Includes 219 billion cubic feet of proved reserves in Venezuela which were expropriated. See note 15, Litigation and Other Contingencies.*

Natural Gas *(continued)*	United States	Canada/ South America *(1)*	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Total
			(billions of cubic feet)				
Proved developed reserves, included above, as of December 31, 2005							
Consolidated subsidiaries	10,386	1,840	6,332	376	6,067	227	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	1,628	5,346	823	5,882	447	23,406
Equity companies	109	—	9,985	—	7,906	811	18,811
Proved developed reserves, included above, as of December 31, 2007							
Consolidated subsidiaries	8,373	1,303	5,064	773	5,570	395	21,478
Equity companies	104	—	9,679	—	8,702	757	19,242

(1) Includes proved developed reserves attributable to Imperial Oil Limited of 643 billion cubic feet in 2005, 608 billion cubic feet in 2006 and 539 billion cubic feet in 2007, 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, 2005	738
At December 31, 2006	718
At December 31, 2007	694

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

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

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	**United States**	**Canada/ South America *(1)***	**Europe**	**Africa**	**Asia Pacific/ Middle East**	**Russia/ Caspian**	**Total**
				(millions of dollars)			
Consolidated subsidiaries							
As of December 31, 2005							
Future cash inflows from sales of oil and gas	$200,119	$ 54,953	$107,127	$127,584	$ 44,411	$ 35,757	$569,951
Future production costs	34,100	14,460	19,958	21,856	12,515	5,324	108,213
Future development costs	8,935	3,562	8,552	12,464	2,651	4,000	40,164
Future income tax expenses	67,581	12,343	47,999	51,610	13,151	6,608	199,292
Future net cash flows	$ 89,503	$ 24,588	$ 30,618	$ 41,654	$ 16,094	$ 19,825	$222,282
Effect of discounting net cash flows at 10%	53,919	10,641	9,988	15,337	6,800	12,379	109,064
Discounted future net cash flows	$ 35,584	$ 13,947	$ 20,630	$ 26,317	$ 9,294	$ 7,446	$113,218
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 7,000	$ —	$ 11,043	$ —	$ 34,214	$ 7,735	$ 59,992
Consolidated subsidiaries							
As of December 31, 2006							
Future cash inflows from sales of oil and gas	$139,843	$ 61,187	$ 83,854	$117,068	$ 100,751	$ 42,264	$544,967
Future production costs	39,829	20,639	19,134	22,316	36,008	3,597	141,523
Future development costs	11,134	4,023	10,245	10,429	6,098	5,307	47,236
Future income tax expenses	42,665	12,951	34,050	48,235	35,200	8,156	181,257
Future net cash flows	$ 46,215	$ 23,574	$ 20,425	$ 36,088	$ 23,445	$ 25,204	$174,951
Effect of discounting net cash flows at 10%	28,428	11,429	6,464	12,069	12,777	16,932	88,099
Discounted future net cash flows	$ 17,787	$ 12,145	$ 13,961	$ 24,019	$ 10,668	$ 8,272	$ 86,852
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 6,337	$ —	$ 7,952	$ —	$ 27,136	$ 8,490	$ 49,915
Consolidated subsidiaries							
As of December 31, 2007							
Future cash inflows from sales of oil and gas	$216,287	$ 49,985	$115,741	$184,358	$ 158,292	$ 64,351	$789,014
Future production costs	59,154	17,422	21,356	34,721	38,098	6,537	177,288
Future development costs	13,422	5,487	10,166	21,258	5,903	7,513	63,749
Future income tax expenses	63,042	7,383	54,065	75,441	83,349	13,387	296,667
Future net cash flows	$ 80,669	$ 19,693	$ 30,154	$ 52,938	$ 30,942	$ 36,914	$251,310
Effect of discounting net cash flows at 10%	51,521	7,607	9,515	20,099	14,021	25,935	128,698
Discounted future net cash flows	$ 29,148	$ 12,086	$ 20,639	$ 32,839	$ 16,921	$ 10,979	$122,612
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 12,045	$ —	$ 11,041	$ —	$ 53,067	$ 15,791	$ 91,944

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $3,723 million in 2005, $5,505 million in 2006 and $6,304 million in 2007, in which there is a 30.4 percent minority interest.

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

Consolidated Subsidiaries	**2007**	**2006**	**2005**
		(millions of dollars)	
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	$ (1,680)[(1)]	$ 14,316	$ 4,619
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	(51,093)	(49,732)	(42,606)
Development costs incurred during the year	9,668	9,465	8,617
Net change in prices, lifting and development costs	108,967	(35,342)	85,049
Revisions of previous reserves estimates	15,855	9,438	9,050
Accretion of discount	15,267	17,368	9,021
Net change in income taxes	(61,224)	8,121	(41,616)
Total change in the standardized measure during the year	$ 35,760	$(26,366)	$ 32,134

(1) Includes impact of expropriation of proved reserves in Venezuela. See note 15, Litigation and Other Contingencies.

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OPERATING SUMMARY (unaudited)

	2007	2006	2005	2004	2003
			(thousands of barrels daily)		
Production of crude oil and natural gas liquids					
Net production					
United States	392	414	477	557	610
Canada/South America	324	354	395	408	411
Europe	480	520	546	583	579
Africa	717	781	666	572	442
Asia Pacific/Middle East	518	485	332	360	386
Russia/Caspian	185	127	107	91	88
Worldwide	2,616	2,681	2,523	2,571	2,516
			(millions of cubic feet daily)		
Natural gas production available for sale					
Net production					
United States	1,468	1,625	1,739	1,947	2,246
Canada/South America	808	935	1,006	1,069	1,044
Europe	3,810	4,086	4,315	4,614	4,498
Africa	26	—	—	—	—
Asia Pacific/Middle East	3,162	2,596	2,114	2,161	2,258
Russia/Caspian	110	92	77	73	73
Worldwide	9,384	9,334	9,251	9,864	10,119
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	4,180	4,237	4,065	4,215	4,203
			(thousands of barrels daily)		
Refinery throughput					
United States	1,746	1,760	1,794	1,850	1,806
Canada	442	442	466	468	450
Europe	1,642	1,672	1,672	1,663	1,566
Asia Pacific	1,416	1,434	1,490	1,423	1,390
Other Non-U.S.	325	295	301	309	298
Worldwide	5,571	5,603	5,723	5,713	5,510
Petroleum product sales (2)					
United States	2,717	2,729	2,822	2,872	2,729
Canada	461	473	498	615	602
Europe	1,773	1,813	1,824	2,139	2,061
Asia Pacific and other Eastern Hemisphere	1,701	1,763	1,902	2,080	2,075
Latin America	447	469	473	504	490
Purchases/sales with the same counterparty included above	—	—	—	(699)	(687)
Worldwide	7,099	7,247	7,519	7,511	7,270
Gasoline, naphthas	2,850	2,866	2,957	3,301	3,238
Heating oils, kerosene, diesel oils	2,094	2,191	2,230	2,517	2,432
Aviation fuels	641	651	676	698	662
Heavy fuels	715	682	689	659	638
Specialty petroleum products	799	857	967	1,035	987
Purchases/sales with the same counterparty included above	—	—	—	(699)	(687)
Worldwide	7,099	7,247	7,519	7,511	7,270
			(thousands of metric tons)		
Chemical prime product sales					
United States	10,855	10,703	10,369	11,521	10,740
Non-U.S.	16,625	16,647	16,408	16,267	15,827
Worldwide	27,480	27,350	26,777	27,788	26,567

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) 2007, 2006 and 2005 petroleum product sales data reported net of purchases/sales contracts with the same counterparty.

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, 2008

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 (Rex W. Tillerson)	Chairman of the Board (Principal Executive Officer)	February 28, 2008
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director	February 28, 2008
/s/ LARRY R. FAULKNER (Larry R. Faulkner)	Director	February 28, 2008

/s/ WILLIAM W. GEORGE (William W. George)	Director	February 28, 2008
/s/ JAMES R. HOUGHTON (James R. Houghton)	Director	February 28, 2008
/s/ WILLIAM R. HOWELL (William R. Howell)	Director	February 28, 2008
/s/ REATHA CLARK KING (Reatha Clark King)	Director	February 28, 2008
/s/ PHILIP E. LIPPINCOTT (Philip E. Lippincott)	Director	February 28, 2008
/s/ MARILYN CARLSON NELSON (Marilyn Carlson Nelson)	Director	February 28, 2008
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director	February 28, 2008
/s/ STEVEN S REINEMUND (Steven S Reinemund)	Director	February 28, 2008
/s/ WALTER V. SHIPLEY (Walter V. Shipley)	Director	February 28, 2008
/s/ J. STEPHEN SIMON (J. Stephen Simon)	Director	February 28, 2008
/s/ DONALD D. HUMPHREYS (Donald D. Humphreys)	Treasurer (Principal Financial Officer)	February 28, 2008
/s/ PATRICK T. MULVA (Patrick T. Mulva)	Controller (Principal Accounting Officer)	February 28, 2008

INDEX TO EXHIBITS

3(i).	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 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, 2007).
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 4, 2007).*
10(iii)(b.1).	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 99.2 to the Registrant's Report on Form 8-K on November 2, 2007).*
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 4, 2007).*
10(iii)(c.1).	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K on November 2, 2007).*
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 Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).*
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 September 26, 2007 (incorporated by reference to Exhibit 99.2 to the Registrant's Report on Form 8-K on September 27, 2007).*
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 26, 2007 (incorporated by reference to Exhibit 99.3 to the Registrant's Report on Form 8-K on September 27, 2007).*

INDEX TO EXHIBITS—(continued)

10(iii)(f.5).	2001 Nonemployee Directors' Deferred Compensation Plan, as amended and restated on September 27, 2007 (incorporated by reference to Exhibit 99.4 to the Registrant's Report on Form 8-K on September 27, 2007).*
10(iii)(g.1).	1995 Mobil Incentive Compensation and Stock Ownership Plan (incorporated 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).*
10(iii)(g.3).	1984 Mobil Compensation Management Retention Plan, as amended and restated on September 27, 2007 (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K on September 27, 2007).*
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.

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* 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.

EXHIBIT 12

EXXON MOBIL CORPORATION

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2007	2006	2005	2004	2003
	(millions of dollars)				
Income from continuing operations	$40,610	$39,500	$36,130	$25,330	$20,960
Excess/(shortfall) of dividends over earnings of affiliates owned less than 50 percent accounted for by the equity method	(537)	(411)	(513)	(475)	(205)
Provision for income taxes(1)	31,065	28,795	24,885	16,644	11,734
Capitalized interest	(182)	(162)	(89)	(180)	(180)
Minority interests in earnings of consolidated subsidiaries	1,005	1,051	795	773	692
	71,961	68,773	61,208	42,092	33,001
Fixed Charges:(1)					
Interest expense—borrowings	179	184	200	182	182
Capitalized interest	558	532	443	515	497
Rental expense representative of interest factor	735	801	593	498	424
Dividends on preferred stock	—	—	7	5	3
	1,472	1,517	1,243	1,200	1,106
Total adjusted earnings available for payment of fixed charges	$73,433	$70,290	$62,451	$43,292	$34,107
Number of times fixed charges are earned	49.9	46.3	50.2	36.1	30.8

Note:

(1) The provision for income taxes and the fixed charges include Exxon Mobil Corporation's share of 50 percent-owned companies and majority-owned subsidiaries that are not consolidated.

Subsidiaries of the Registrant (1), (2) and (3) – at December 31, 2007

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Abu Dhabi Petroleum Company Limited (5)	23.75	United Kingdom
Aera Energy LLC (5)	48.2	California
Al-Jubail Petrochemical Company (4) (5)	50	Saudi Arabia
Ampolex (CEPU) Pte Ltd	100	Singapore
Ancon Insurance Company, Inc.	100	Vermont
BEB Erdgas und Erdoel GmbH (4) (5)	50	Germany
Cameroon Oil Transportation Company S.A. (5)	41.07	Cameroon
Caspian Pipeline Consortium (5)	7.5	Russia/Kazakhstan
Castle Peak Power Company Limited (5)	60	Hong Kong
Chalmette Refining, LLC (4) (5)	50	Delaware
Esso Australia Resources Pty Ltd	100	Australia
Esso Austria GmbH	100	Austria
Esso Brasileira de Petroleo Limitada	100	Brazil
Esso Chile Petrolera Limitada	100	Chile
Esso Deutschland GmbH	100	Germany
Esso Erdgas Beteiligungsgesellschaft mbH	100	Germany
Esso Espanola, S.L.	100	Spain
Esso Exploration and Production Angola (Block 31) Limited	100	Bahamas
Esso Exploration and Production Chad Inc.	100	Delaware
Esso Exploration and Production Nigeria (Deepwater) Limited	100	Nigeria
Esso Exploration and Production Nigeria Limited	100	Nigeria
Esso Exploration and Production UK Limited	100	United Kingdom
Esso Exploration Angola (Block 15) Limited	100	Bahamas
Esso Exploration Angola (Block 17) Limited	100	Bahamas
Esso Highlands Limited	100	Papua New Guinea
Esso Holding Company Singapore Limited	100	Bahamas
Esso Ireland Limited	100	Ireland
Esso Italiana S.r.l.	100	Italy
Esso Malaysia Berhad	65	Malaysia
Esso Natuna Ltd.	100	Bermuda
Esso Nederland B.V.	100	Netherlands
Esso Norge AS	100	Norway
Esso Petrolera Argentina Sociedad de Responsabilidad Limitada	100	Argentina
Esso Petroleum Company, Limited	100	United Kingdom
Esso Pipeline Investments Limited	100	Bahamas
Esso Raffinage S.A.F.	82.89	France
Esso Schweiz GmbH	100	Switzerland
Esso Societe Anonyme Francaise	82.89	France
Esso (Thailand) Public Company Limited	87.5	Thailand
Esso Trading Company of Abu Dhabi	100	Delaware
Exxon Azerbaijan Caspian Sea Limited	100	Bahamas
Exxon Azerbaijan Limited	100	Bahamas
Exxon Chemical Arabia Inc.	100	Delaware
Exxon International Finance Company	100	Delaware

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Exxon Luxembourg Holdings LLC	100	Delaware
Exxon Mobile Bay Limited Partnership	100	Delaware
Exxon Neftegas Limited	100	Bahamas
Exxon Overseas Investment Corporation	100	Delaware
ExxonMobil Abu Dhabi Offshore Petroleum Company Limited	100	Bahamas
ExxonMobil Alaska Production Inc.	100	Delaware
ExxonMobil Asia Pacific Pte. Ltd.	100	Singapore
ExxonMobil Aviation International Limited	100	United Kingdom
ExxonMobil Canada Energy	100	Canada
ExxonMobil Canada Finance Company	100	Canada
ExxonMobil Canada Ltd.	100	Canada
ExxonMobil Canada Properties	100	Canada
ExxonMobil Canada Resources Company	100	Canada
ExxonMobil Capital N.V.	100	Netherlands
ExxonMobil Catalyst Technologies LLC	100	Delaware
ExxonMobil Central Europe Holding GmbH	100	Germany
ExxonMobil Chemical Central Europe GmbH	100	Germany
ExxonMobil Chemical Films Europe, Inc.	100	Delaware
ExxonMobil Chemical France S.A.R.L.	99.77	France
ExxonMobil Chemical Holland B.V.	100	Netherlands
ExxonMobil Chemical Limited	100	United Kingdom
ExxonMobil Chemical Operations Private Limited	100	Singapore
ExxonMobil China Petroleum & Petrochemical Company Limited	100	Bahamas
ExxonMobil de Colombia S.A.	99.64	Colombia
ExxonMobil Deepwater Holdings B.V.	100	Netherlands
ExxonMobil Delaware Holdings Inc.	100	Delaware
ExxonMobil Egypt (S.A.E.)	100	Egypt
ExxonMobil Energy Limited	100	Hong Kong
ExxonMobil Exploration and Production Malaysia Inc.	100	Delaware
ExxonMobil Exploration and Production Norway AS	100	Norway
ExxonMobil Finance Company Limited	100	United Kingdom
ExxonMobil Financial Services B.V.	100	Netherlands
ExxonMobil Gas Marketing Deutschland GmbH	99.999	Germany
ExxonMobil Gas Marketing Deutschland GmbH & Co. KG	50	Germany
ExxonMobil Gas Marketing Europe Limited	100	United Kingdom
ExxonMobil Global Services Company	100	Delaware
ExxonMobil Holding Company Holland LLC	100	Delaware
ExxonMobil Holding Norway AS	100	Norway
ExxonMobil Hong Kong Limited	100	Hong Kong
ExxonMobil Hungary Finance Kft.	100	Hungary
ExxonMobil International Holdings Inc.	100	Delaware
ExxonMobil International Services, SARL	100	Luxembourg
ExxonMobil Italiana Gas S.r.l	100	Italy
ExxonMobil Kazakhstan Inc.	100	Bahamas
ExxonMobil Kazakhstan Ventures Inc.	100	Delaware
ExxonMobil Luxembourg UK, SARL	100	Luxembourg
ExxonMobil Malaysia Sdn Bhd	100	Malaysia
ExxonMobil Marine Limited	100	United Kingdom
ExxonMobil Middle East Gas Marketing Limited	100	Bahamas

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
ExxonMobil Oil & Gas Investments Limited	100	Bahamas
ExxonMobil Oil Corporation	100	New York
ExxonMobil Oil Indonesia Inc.	100	Cayman Island
ExxonMobil Pensions-Verwaltungsgesellschaft mbH	100	Germany
ExxonMobil Permian Basin Inc.	100	Delaware
ExxonMobil Petroleum & Chemical, BVBA	100	Belgium
ExxonMobil Petroleum & Chemical Holdings Inc.	100	Delaware
ExxonMobil Pipeline Company	100	Delaware
ExxonMobil Production Deutschland GmbH	100	Germany
ExxonMobil Production Norway Inc.	100	Delaware
ExxonMobil Qatargas Inc.	100	Delaware
ExxonMobil Qatargas (II) Limited	100	Bahamas
ExxonMobil Qatargas (II) Surety Corporation	100	Delaware
ExxonMobil Qatargas (II) Terminal Company Limited	100	Bahamas
ExxonMobil Rasgas Inc.	100	Delaware
ExxonMobil Sales and Supply LLC	100	Delaware
ExxonMobil Southwest Holdings Inc.	100	Delaware
ExxonMobil Yugen Kaisha	100	Japan
Fina Antwerp Olefins N.V. (5)	35	Belgium
Fujian Refining & Petrochemical Co. Ltd. (5)	25	China
Imperial Oil Limited	69.6	Canada
Imperial Oil Petroliere Imperiale, (an Ontario General Partnership)	69.6	Canada
Imperial Oil Resources (an Alberta limited partnership)	69.6	Canada
Imperial Oil Resources Limited	69.6	Canada
Imperial Oil Resources N.W.T. Limited	69.6	Canada
Imperial Oil Resources Ventures Limited	69.6	Canada
Infineum Holdings B.V. (5)	49.96	Netherlands
Kyokuto Petroleum Industries, Ltd. (4) (5)	50	Japan
Mineraloelraffinerie Oberrhein GmbH & Co. KG (5)	25	Germany
Mobil Argentina S.A.	100	Argentina
Mobil Australia Resources Company Pty Limited	100	Australia
Mobil California Exploration & Producing Asset Company	100	Delaware
Mobil Caspian Pipeline Company	100	Delaware
Mobil Cerro Negro, Ltd.	100	Bahamas
Mobil Corporation	100	Delaware
Mobil Equatorial Guinea Inc.	100	Delaware
Mobil Erdgas-Erdoel GmbH	99.999	Germany
Mobil Exploration Indonesia Inc.	100	Cayman Island
Mobil Exploration and Producing North America Inc.	100	Nevada
Mobil International Finance Corporation	100	Delaware
Mobil International Petroleum Corporation	100	Delaware
Mobil North Sea L.L.C.	100	Delaware
Mobil Oil Australia Pty Ltd	100	Australia
Mobil Oil Exploration & Producing Southeast Inc.	100	Delaware
Mobil Oil New Zealand Limited	100	New Zealand
Mobil Petroleum Company Inc.	100	Delaware
Mobil Pipe Line Company	100	Delaware
Mobil Producing Nigeria Unlimited	100	Nigeria
Mobil Producing Texas & New Mexico Inc.	100	Delaware

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Mobil Refining Australia Pty Ltd	100	Australia
Mobil Services (Bahamas) Limited	100	Bahamas
Mobil Yanbu Petrochemical Company Inc.	100	Delaware
Mobil Yanbu Refining Company Inc.	100	Delaware
Nansei Sekiyu Kabushiki Kaisha (6)	43.77	Japan
Nederlandse Aardolie Maatschappij B.V. (4) (5)	50	Netherlands
PR Jotun DA (5)	45	Norway
Qatar Liquefied Gas Company Limited (5)	10	Qatar
Qatar Liquefied Gas Company Limited (II) (5)	24.15	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (5)	24.999	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (II) (5)	30	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (3) (5)	30	Qatar
Samoco LLC (4)	50	Cayman Island
Saudi Aramco Mobil Refinery Company Ltd. (4) (5)	50	Saudi Arabia
Saudi Yanbu Petrochemical Co. (4) (5)	50	Saudi Arabia
SeaRiver Maritime Financial Holdings, Inc.	100	Delaware
SeaRiver Maritime, Inc.	100	Delaware
Societa per Azioni Raffineria Padana Olii Minerali - SARPOM	74.14	Italy
Societe Francaise ExxonMobil Chemical SCA	99.77	France
South Hook LNG Terminal Company Limited (5)	30	United Kingdom
Standard Tankers Bahamas Limited	100	Bahamas
Tengizchevroil, LLP (5)	25	Kazakhstan
Terminale GNL Adriatico S.r.l. (5)	45	Italy
TonenGeneral Sekiyu K.K.	50.021	Japan
Tonen Kagaku K.K.	50.021	Japan

NOTES:

(1) For the purposes of this list, if the registrant owns directly or indirectly approximately 50 percent of the voting securities of any person and approximately 50 percent of the voting securities of such person is owned directly or indirectly by another interest, or if the registrant includes its share of net income of any other unconsolidated person in consolidated net income, such person is deemed to be a subsidiary.

(2) With respect to certain companies, shares in names of nominees and qualifying shares in names of directors are included in the above percentages.

(3) The names of other subsidiaries have been omitted from the above list since considered in the aggregate, they would not constitute a significant subsidiary under Securities and Exchange Commission Regulation S-X, Rule 1-02(w).

(4) The registrant owns directly or indirectly approximately 50 percent of the securities of this person and approximately 50 percent of the voting securities of this person is owned directly or indirectly by another single interest.

(5) The investment in this unconsolidated person is represented by the registrant’s percentage interest in the underlying net assets of such person. The accounting for these unconsolidated persons is referred to as the equity method of accounting.

(6) The percentage interest shown reflects an 87.5% ownership of voting securities by TonenGeneral Sekiyu K.K., of which the registrant owns 50.021% of voting securities.

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the following Exxon Mobil Corporation Registration Statements on:

Form S-3 (No. 33-48919)	—	Guaranteed Debt Securities and Warrants to Purchase Guaranteed Debt Securities of Exxon Capital Corporation;
Form S-3 (No. 33-8922)	—	Guaranteed Debt Securities of SeaRiver Maritime Financial Holdings, Inc. (formerly Exxon Shipping Company);
Form S-8 (Nos. 333-101175, 333-38917 and 33-51107)	—	1993 Incentive Program of Exxon Mobil Corporation;
Form S-8 (No. 333-145188) and 333-110494)	—	2003 Incentive Program of Exxon Mobil Corporation;
Form S-8 (No. 333-69378)	—	ExxonMobil Fuels Marketing Savings Plan;
Form S-8 (No. 333-72955)	—	ExxonMobil Savings Plan;
Form S-8 (No. 333-75659)	—	Post-Effective Amendment No. 2 on Form S-8 to Form S-4 which pertains to the 1993 Incentive Program of Exxon Mobil Corporation;
Form S-8 (No. 333-117980)	—	2004 Non-employee Director Restricted Stock Plan

of our report dated February 28, 2008, relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/S/ PRICEWATERHOUSECOOPERS LLP

Dallas, Texas
February 28, 2008

EXHIBIT 31.1

Certification by Rex W. Tillerson
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Rex W. Tillerson, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ REX W. TILLERSON
Rex W. Tillerson
Chief Executive Officer

EXHIBIT 31.2

Certification by Donald D. Humphreys
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Donald D. Humphreys, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ DONALD D. HUMPHREYS

Donald D. Humphreys
Senior Vice President and Treasurer
(Principal Financial Officer)

EXHIBIT 31.3

Certification by Patrick T. Mulva
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Patrick T. Mulva, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ PATRICK T. MULVA

Patrick T. Mulva
Vice President and Controller
(Principal Accounting Officer)

EXHIBIT 32.1

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Rex W. Tillerson, the chief executive officer of Exxon Mobil Corporation (the “Company”), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the “Report”) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2008

/s/ REX W. TILLERSON

Rex W. Tillerson
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Donald D. Humphreys, the principal financial officer of Exxon Mobil Corporation (the "Company"), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2008

/s/ DONALD D. HUMPHREYS

Donald D. Humphreys
Senior Vice President and Treasurer
(Principal Financial Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.3

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Patrick T. Mulva, the principal accounting officer of Exxon Mobil Corporation (the “Company”), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the “Report”) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2008

/s/ PATRICK T. MULVA

Patrick T. Mulva
Vice President and Controller
(Principal Accounting Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Exxon Mobil Corporation
5959 Las Colinas Boulevard
Irving, Texas 75039-2298

ExxonMobil (logo)

February 28, 2008

Exxon Mobil Corporation
2007 Annual Report on Form 10-K

Securities and Exchange Commission
100 F Street N.E.
Washington, D.C. 20549

Attention: EDGAR Document Control

Dear Sirs:

Transmitted with this cover note is Exxon Mobil Corporation's 2007 Annual Report on Form 10-K.

Except as noted below, the financial statements contained in ExxonMobil's 2007 Annual Report on Form 10-K do not reflect any material changes from the preceding year resulting from changes in any accounting principles or practices, or in the method of applying such principles or practices.

- Effective January 1, 2007, the Corporation adopted the Financial Accounting Standards Board's (FASB) Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes." FIN 48 is an interpretation of FASB Statement 109, "Accounting for Income Taxes," and prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that the Corporation has taken or expects to take in its income tax returns. Upon the adoption of FIN 48, the Corporation recognized a transition gain of $267 million in shareholders' equity. The gain reflected the recognition of several refund claims, partly offset by increased liability reserves. FIN 48 also resulted in reclassification of amounts previously reported net on the balance sheet. The balance sheet reclassifications resulted in a $2.4 billion increase to investments, advances and long-term receivables, a $1.0 billion decrease in current liabilities, primarily income taxes payable, and a $3.1 billion increase to other long-term obligations.

Sincerely,

/s/ David S. Rosenthal
David S. Rosenthal
Assistant Controller

Attachments