EXXON MOBIL CORP
Form 10-K
February 26, 2014

2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013

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 (4,321,238,544 shares outstanding at January 31, 2014)	**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 x 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 x

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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 x 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 x

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $90.35 on the New York Stock Exchange composite tape, was in excess of $397 billion.

Documents Incorporated by Reference: Proxy Statement for the 2014 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013

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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, Mobil* or *XTO*. For convenience and simplicity, in this report the terms *ExxonMobil, Exxon, Esso, Mobil* and *XTO*, 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 monitor and reduce nitrogen oxide, sulfur oxide, and greenhouse gas emissions and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2013 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $6.0 billion, of which $3.5 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to remain in this range in 2014 and 2015 (with capital expenditures approximately 45 percent of the total).

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.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the following: "Quarterly Information", "Note 18: 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.

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in each of our business segments. Information on Company-sponsored research and development spending is contained in "Note 3: Miscellaneous Financial Information" of the Financial Section of this report. ExxonMobil held approximately 11 thousand active patents worldwide at the end of 2013. For technology licensed to third parties, revenues totaled approximately $195 million in 2013. Although technology is an important contributor to the overall operations and results of our Company, the profitability of each business segment is not dependent on any individual patent, trade secret, trademark, license, franchise or concession.

The number of regular employees was 75.0 thousand, 76.9 thousand and 82.1 thousand at years ended 2013, 2012 and 2011, 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 9.8 thousand, 11.1 thousand and 17.0 thousand at years ended 2013, 2012 and 2011, respectively.

Information concerning the source and availability of raw materials used in the Corporation's business, the extent of seasonality in the business, the possibility of renegotiation of profits or termination of contracts at the election of governments and risks attendant to foreign operations may be found in "Item 1A–Risk Factors" and "Item 2–Properties" in this report.

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. Information on our website is not incorporated into this report.

ITEM 1A. RISK FACTORS

ExxonMobil's financial and operating results are subject to a variety of risks inherent in the global oil, gas, and petrochemical businesses. Many of these risk factors are not within the Company's control and could adversely affect our business, our financial and operating results or our financial condition. These risk factors include:

Supply and Demand

The oil, gas, and petrochemical businesses are fundamentally commodity businesses. This means ExxonMobil's operations and earnings may be significantly affected by changes in oil, gas and petrochemical prices and by changes in margins on 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.

Economic conditions. The demand for energy and petrochemicals correlates closely with general economic growth rates. The occurrence of recessions or other periods of low or negative economic growth will typically have a direct adverse impact on our results. Other factors that affect general economic conditions in the world or in a major region, such as changes in population growth rates, periods of civil unrest, government austerity programs, or currency exchange rate fluctuations, can also impact the demand for energy and petrochemicals. Sovereign debt downgrades, defaults, inability to access debt markets due to credit or legal constraints, liquidity crises, the breakup or restructuring of fiscal, monetary, or political systems such as the European Union, and other events or conditions that impair the functioning of financial markets and institutions also pose risks to ExxonMobil, including risks to the safety of our financial assets and to the ability of our partners and customers to fulfill their commitments to ExxonMobil.

Other demand-related factors. Other factors that may affect the demand for oil, gas and petrochemicals, and therefore impact our results, include technological improvements in energy efficiency; seasonal weather patterns, which affect the demand for energy associated with heating and cooling; increased competitiveness of alternative energy sources that have so far generally not been competitive with oil and gas without the benefit of government subsidies or mandates; and changes in technology or consumer preferences that alter fuel choices, such as toward alternative fueled vehicles.

Other supply-related factors. Commodity prices and margins also vary depending on a number of factors affecting supply. For example, increased supply from the development of new oil and gas supply sources and technologies to enhance recovery from existing sources tend to reduce commodity prices to the extent such supply increases are not offset by commensurate growth in demand. Similarly, increases in industry refining or petrochemical manufacturing capacity tend to reduce margins on the affected products. World oil, gas, and petrochemical supply levels can also be affected by factors that reduce available supplies, such as adherence by member countries to OPEC production quotas and the occurrence of wars, hostile actions, natural disasters, disruptions in competitors' operations, or unexpected unavailability of distribution channels that may disrupt supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oil and gas and to manufacture petrochemicals.

Other market factors. ExxonMobil's business results are also exposed to potential negative impacts due to changes in interest rates, inflation, currency exchange rates, and other local or regional market conditions. We generally do not use financial instruments to hedge market exposures.

Government and Political Factors

ExxonMobil's results can be adversely affected by political or regulatory developments affecting our operations.

Access limitations. A number of countries limit access to their oil and gas resources, or may place resources off-limits from development altogether. Restrictions on foreign investment in the oil and gas sector tend to increase in times of high commodity prices, when national governments may have less need of outside sources of private capital. Many countries also restrict the import or export of certain products based on point of origin.

Restrictions on doing business. As a U.S. company, ExxonMobil is subject to laws prohibiting U.S. companies from doing business in certain countries, or restricting the kind of business that may be conducted. Such restrictions may provide a competitive advantage to our non-U.S. competitors unless their own home countries impose comparable restrictions.

Lack of legal certainty. Some countries in which we do business lack well-developed legal systems, or have not yet adopted clear regulatory frameworks for oil and gas development. Lack of legal certainty exposes our operations to increased risk of adverse or unpredictable actions by government officials, and also makes it more difficult for us to enforce our contracts. In some cases these risks can be partially offset by agreements to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal system to enforce an award.

Regulatory and litigation risks. Even in countries with well-developed legal systems where ExxonMobil does business, we remain exposed to changes in law (including changes that result from international treaties and accords) that could adversely affect our results, such as:

•	increases in taxes or government royalty rates (including retroactive claims);
•	price controls;
•	changes in environmental regulations or other laws that increase our cost of compliance or reduce or delay available business opportunities (including changes in laws related to offshore drilling operations, water use, or hydraulic fracturing);
•	adoption of regulations mandating the use of alternative fuels or uncompetitive fuel components;
•	adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information, or that could cause us to violate the non-disclosure laws of other countries; and
•	government actions to cancel contracts, re-denominate the official currency, renounce or default on obligations, renegotiate terms unilaterally, or expropriate assets.

Legal remedies available to compensate us for expropriation or other takings may be inadequate.

We also may be adversely affected by the outcome of litigation, especially in countries such as the United States in which very large and unpredictable punitive damage awards may occur, or by government enforcement proceedings alleging non-compliance with applicable laws or regulations.

Security concerns. Successful operation of particular facilities or projects may be disrupted by civil unrest, acts of sabotage or terrorism, and other local security concerns. Such concerns may require us to incur greater costs for security or to shut down operations for a period of time.

Climate change and greenhouse gas restrictions. Due to concern over the risk of climate change, a number of countries have adopted, or are considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions. These include adoption of cap and trade regimes, carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates for renewable energy. These requirements could make our products more expensive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shift hydrocarbon demand toward relatively lower-carbon sources such as natural gas. Current and pending greenhouse gas regulations may also increase our compliance costs, such as for monitoring or sequestering emissions.

Government sponsorship of alternative energy. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. We are conducting our own research efforts into alternative energy, such as through sponsorship of the Global Climate and Energy Project at Stanford University and research into liquid products from algae and biomass that can be further converted to transportation fuels. Our future results may depend in part on the success of our research efforts and on our ability to adapt and apply the strengths of our current business model to providing the energy products of the future in a cost-competitive manner. See “Management Effectiveness” below.

Management Effectiveness

In addition to external economic and political factors, our future business results also depend on our ability to manage successfully those factors that are at least in part within our control. The extent to which we manage these factors will impact our performance relative to competition. For projects in which we are not the operator, we depend on the management effectiveness of one or more co-venturers whom we do not control.

Exploration and development program. Our ability to maintain and grow our oil and gas production depends on the success of our exploration and development efforts. Among other factors, we must continuously improve our ability to identify the most promising resource prospects and apply our project management expertise to bring discovered resources on line on schedule and within budget.

Project management. The success of ExxonMobil's Upstream, Downstream, and Chemical businesses depends on complex, long-term, capital intensive projects. These projects in turn require a high degree of project management expertise to maximize efficiency. Specific factors that can affect the performance of major projects include our ability to: negotiate successfully with joint venturers, partners, governments, suppliers, customers, or others; model and optimize reservoir performance; develop markets for project outputs, whether through long-term contracts or the development of effective spot markets; manage changes in operating conditions and costs, including costs of third party equipment or services such as drilling rigs and shipping; prevent, to the extent possible, and respond effectively to unforeseen technical difficulties that could delay project startup or cause unscheduled project downtime; and influence the performance of project operators where ExxonMobil does not perform that role.

The term “project” as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

Operational efficiency. An important component of ExxonMobil’s competitive performance, especially given the commodity-based nature of many of our businesses, is our ability to operate efficiently, including our ability to manage expenses and improve production yields on an ongoing basis. This requires continuous management focus, including technology improvements, cost control, productivity enhancements, regular reappraisal of our asset portfolio, and the recruitment, development and retention of high caliber employees.

Research and development. To maintain our competitive position, especially in light of the technological nature of our businesses and the need for continuous efficiency improvement, ExxonMobil’s research and development organizations must be successful and able to adapt to a changing market and policy environment.

Safety, business controls, and environmental risk management. Our results depend on management’s ability to minimize the inherent risks of oil, gas, and petrochemical operations, to control effectively our business activities and to minimize the potential for human error. We apply rigorous management systems and continuous focus to workplace safety and to avoiding spills or other adverse environmental events. For example, we work to minimize spills through a combined program of effective operations integrity management, ongoing upgrades, key equipment replacements, and comprehensive inspection and surveillance. Similarly, we are implementing cost-effective new technologies and adopting new operating practices to reduce air emissions, not only in response to government requirements but also to address community priorities. We also maintain a disciplined framework of internal controls and apply a controls management system for monitoring compliance with this framework. Substantial liabilities and other adverse impacts could result if our management systems and controls do not function as intended. The ability to insure against such risks is limited by the capacity of the applicable insurance markets, which may not be sufficient.

Business risks also include the risk of cybersecurity breaches. If our systems for protecting against cybersecurity risks prove not to be sufficient, ExxonMobil could be adversely affected such as by having its business systems compromised, its proprietary information altered, lost or stolen, or its business operations disrupted.

Preparedness. Our operations may be disrupted by severe weather events, natural disasters, human error, and similar events. For example, hurricanes may damage our offshore production facilities or coastal refining and petrochemical plants in vulnerable areas. Our ability to mitigate the adverse impacts of these events depends in part upon the effectiveness of our rigorous disaster preparedness and response planning, as well as business continuity planning.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Item 2. Properties

Information with regard to oil and gas producing activities follows:

1. Disclosure of Reserves

A. Summary of Oil and Gas Reserves at Year-End 2013

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. The Corporation has reported proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No major discovery or other favorable or adverse event has occurred since December 31, 2013, that would cause a significant change in the estimated proved reserves as of that date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equivalent Basis
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,212	257	-	-	14,655	3,912
Canada/South America *(1)*	111	15	1,810	579	664	2,626
Europe	210	39	-	-	2,189	613
Africa	765	180	-	-	779	1,075
Asia	1,525	138	-	-	5,241	2,537
Australia/Oceania	56	49	-	-	969	266
Total Consolidated	3,879	678	1,810	579	24,497	11,029
Equity Companies						
United States	258	10	-	-	197	301
Europe	27	-	-	-	6,852	1,169
Asia	902	390	-	-	17,288	4,173
Total Equity Company	1,187	400	-	-	24,337	5,643
Total Developed	5,066	1,078	1,810	579	48,834	16,672

Undeveloped							
Consolidated Subsidiaries							
United States	796	272	-	-	11,365	2,962
Canada/South America *(1)*	173	4	1,820	-	571	2,092
Europe	35	16	-	-	621	155
Africa	428	21	-	-	88	464
Asia	638	-	-	-	493	720
Australia/Oceania	99	32	-	-	6,546	1,222
Total Consolidated	2,169	345	1,820	-	19,684	7,615
Equity Companies						
United States	72	5	-	-	84	91
Europe	1	-	-	-	2,032	340
Asia	243	51	-	-	1,226	498
Total Equity Company	316	56	-	-	3,342	929
Total Undeveloped	2,485	401	1,820	-	23,026	8,544
Total Proved Reserves	7,551	1,479	3,630	579	71,860	25,216

(1) South America includes proved developed reserves of 0.2 million barrels of crude oil and natural gas liquids and 44 billion cubic feet of natural gas and proved undeveloped reserves of 0.1 million barrels of crude oil and natural gas liquids and 10 billion cubic feet of natural gas.

In the preceding reserves information, 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 2014-2018. 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 and reservoir 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.

B. Technologies Used in Establishing Proved Reserves Additions in 2013

Additions to ExxonMobil's proved reserves in 2013 were based on estimates generated through the integration of available and appropriate geological, engineering and production data, utilizing well-established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements including high-quality 2-D and 3-D seismic data, calibrated with available well control information. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software, and commercially available data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

C. Qualifications of Reserves Technical Oversight Group and Internal Controls over Proved Reserves

ExxonMobil has a dedicated Global Reserves group that provides technical oversight and is separate from the operating organization. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This group also maintains the official company reserves estimates for ExxonMobil's proved reserves of crude and natural gas liquids, bitumen, synthetic oil and natural gas. In addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its affiliates. The Manager of the Global Reserves group has more than 30 years of experience in reservoir engineering and reserves assessment and has a degree in Engineering. He is an active member of the Society of Petroleum Engineers (SPE) and previously served on the SPE Oil and Gas Reserves Committee. The

group is managed by and staffed with individuals that have an average of more than 20 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under the SEC guidelines. This group includes individuals who hold advanced degrees in either Engineering or Geology. Several members of the group hold professional registrations in their field of expertise, and members have served on the SPE Oil and Gas Reserves Committee.

The Global Reserves group maintains a central database containing the official company reserves estimates. Appropriate controls, including limitations on database access and update capabilities, are in place to ensure data integrity within this central database. An annual review of the system's controls is performed by internal audit. Key components of the reserves estimation process include technical evaluations and analysis of well and field performance and a rigorous peer review. No changes may be made to the reserves estimates in the central database, including additions of any new initial reserves estimates or subsequent revisions, unless these changes have been thoroughly reviewed and evaluated by duly authorized personnel within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require further review and approval of the appropriate level of management within the operating organization before the changes may be made in the central database. Endorsement by the Global Reserves group for all proved reserves changes is a mandatory component of this review process. After all changes are made, reviews are held with senior management for final endorsement.

2. Proved Undeveloped Reserves

At year-end 2013, approximately 8.5 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 34 percent of the 25.2 GOEB reported in proved reserves. This compares to the 9.9 GOEB of proved undeveloped reserves reported at the end of 2012. The net decrease is primarily due to project startups in Canada and Kazakhstan. During the year, ExxonMobil conducted development activities in over 100 fields that resulted in the transfer of approximately 1.9 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related to Kearl Initial Development startup and new pad steam injection in the Cold Lake field in Canada, Kashagan field startup in Kazakhstan and the Groningen compression assessment in the Netherlands.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments toward the development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order to be developed. Development projects typically take two to four years from the time of first recording of proved reserves to the start of production of these reserves. However, the development time for large and complex projects can exceed five years. During 2013, discoveries and extensions related to new projects added approximately 0.7 GOEB of proved undeveloped reserves. The largest of these additions were related to planned drilling in the United States and Upper Zakum field expansion in Abu Dhabi. Overall, investments of $25.3 billion were made by the Corporation during 2013 to progress the development of reported proved undeveloped reserves, including $22.7 billion for oil and gas producing activities and an additional $2.6 billion for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities that were undertaken to progress the development of proved undeveloped reserves. These investments represented 66 percent of the $38.2 billion in total reported Upstream capital and exploration expenditures.

Proved undeveloped reserves in Australia, Papua New Guinea, the United States, Kazakhstan, Nigeria, and the Netherlands have remained undeveloped for five years or more primarily due to constraints on the capacity of infrastructure, the pace of co-venturer/government funding, as well as the time required to complete development for very large projects. The Corporation is reasonably certain that these proved reserves will be produced; however, 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. Of the proved undeveloped reserves that have been reported for five or more years, 91 percent are contained in the aforementioned countries. The largest of these is related to LNG/Gas projects in Australia and Papua New Guinea, where construction of the initial development is under way. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the initial development of the offshore Kashagan field which is included in the North Caspian Production Sharing Agreement and the Tengizchevroil joint venture which includes a production license in the Tengiz – Korolev field complex. The Tengizchevroil joint venture is producing, and proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the Netherlands, the Groningen gas field has proved undeveloped reserves reported that are related to installation of future stages of compression. These reserves will move to proved developed when the additional stages of compression are installed to maintain field delivery pressure.

3. Oil and Gas Production, Production Prices and Production Costs

A. Oil and Gas Production

The table below summarizes production by final product sold and by geographic area for the last three years.

	2013		2012		2011	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	283	85	274	81	280	77
Canada/South America *(1)*	57	10	49	10	53	12
Europe	157	27	170	33	219	46
Africa	451	18	472	15	491	17
Asia	313	30	319	43	329	54
Australia/Oceania	29	19	32	18	34	17
Total Consolidated Subsidiaries	1,290	189	1,316	200	1,406	223
Equity Companies						
United States	61	2	61	2	65	1
Europe	6	-	4	-	5	-
Asia	373	68	345	65	358	67
Total Equity Companies	440	70	410	67	428	68
Total crude oil and natural gas liquids production	1,730	259	1,726	267	1,834	291
Bitumen production						
Consolidated Subsidiaries						
Canada/South America	148		123		120	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/South America	65		69		67	
Total liquids production	2,202		2,185		2,312	
	(millions of cubic feet daily)					
Natural gas production available for sale						

	Consolidated Subsidiaries											
		United States			3,530			3,819			3,917	
		Canada/South America *(1)*			354			362			412	
		Europe			1,294			1,446			1,701	
		Africa			6			17			7	
		Asia			1,180			1,445			1,879	
		Australia/Oceania			351			363			331	
			Total Consolidated Subsidiaries		6,715			7,452			8,247	
	Equity Companies											
		United States			15			3			-	
		Europe			1,957			1,774			1,747	
		Asia			3,149			3,093			3,168	
			Total Equity Companies		5,121			4,870			4,915	
Total natural gas production available for sale					11,836			12,322			13,162	
					(thousands of oil-equivalent barrels daily)							
Oil-equivalent production					4,175			4,239			4,506	

(1) South America includes liquids production for 2012 and 2011 of one thousand barrels daily for each year and natural gas production available for sale for 2013, 2012 and 2011 of 28 million, 38 million, and 45 million cubic feet daily, respectively.

B. Production Prices and Production Costs

The table below summarizes average production prices and average production costs by geographic area and by product type for the last three years.

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
During 2013	*(dollars per unit)*						
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	93.56	98.91	106.75	108.73	106.18	107.92	104.13
NGL, per barrel	44.30	44.96	65.36	75.24	40.83	59.55	51.12
Natural gas, per thousand cubic feet	2.99	2.80	10.07	2.79	4.10	4.20	4.60
Bitumen, per barrel	-	59.63	-	-	-	-	59.63
Synthetic oil, per barrel	-	93.96	-	-	-	-	93.96
Average production costs, per oil-equivalent barrel - total	12.02	32.02	19.57	13.95	8.95	16.81	15.42
Average production costs, per barrel - bitumen	-	34.30	-	-	-	-	34.30
Average production costs, per barrel - synthetic oil	-	50.94	-	-	-	-	50.94
Equity Companies							
Average production prices							
Crude oil, per barrel	102.24	-	99.26	-	103.96	-	103.66
NGL, per barrel	42.02	-	-	-	70.90	-	69.96
Natural gas, per thousand cubic feet	4.37	-	9.28	-	10.19	-	9.82
Average production costs, per oil-equivalent barrel - total	22.77	-	3.79	-	1.87	-	3.36
Total							

		Average production prices																	
			Crude oil, per barrel		95.11		98.91		106.49		108.73		104.98		107.92		104.01
			NGL, per barrel		44.24		44.96		65.36		75.24		61.64		59.55		56.26
			Natural gas, per thousand cubic feet		3.00		2.80		9.59		2.79		8.53		4.20		6.86
			Bitumen, per barrel		-		59.63		-		-		-		-		59.63
			Synthetic oil, per barrel		-		93.96		-		-		-		-		93.96
		Average production costs, per oil-equivalent barrel - total			12.72		32.02		12.42		13.95		4.41		16.81		11.48
		Average production costs, per barrel - bitumen			-		34.30		-		-		-		-		34.30
		Average production costs, per barrel - synthetic oil			-		50.94		-		-		-		-		50.94
During 2012																			
	Consolidated Subsidiaries																		
		Average production prices																	
			Crude oil, per barrel		94.71		98.67		110.91		111.19		109.95		112.12		107.05
			NGL, per barrel		50.32		57.84		68.08		76.63		43.65		56.85		54.71
			Natural gas, per thousand cubic feet		2.15		1.98		8.92		2.77		3.91		4.39		3.90
			Bitumen, per barrel		-		58.91		-		-		-		-		58.91
			Synthetic oil, per barrel		-		92.77		-		-		-		-		92.77
		Average production costs, per oil-equivalent barrel - total			11.14		26.94		15.06		13.35		7.27		12.11		13.02
		Average production costs, per barrel - bitumen			-		23.71		-		-		-		-		23.71
		Average production costs, per barrel - synthetic oil			-		47.45		-		-		-		-		47.45
	Equity Companies																		
		Average production prices																	
			Crude oil, per barrel		105.02		-		104.59		-		106.59		-		106.33
			NGL, per barrel		58.38		-		-		-		75.24		-		74.87
			Natural gas, per thousand cubic		3.22		-		9.66		-		9.38		-		9.48

			feet															
		Average production costs, per oil-equivalent barrel - total			20.15		-		3.36		-		1.43		-		2.80
	Total																	
		Average production prices																
			Crude oil, per barrel		96.60		98.67		110.74		111.19		108.22		112.12		106.88
			NGL, per barrel		50.46		57.84		68.08		76.63		62.61		56.85		59.74
			Natural gas, per thousand cubic feet		2.15		1.98		9.33		2.77		7.64		4.39		6.11
			Bitumen, per barrel		-		58.91		-		-		-		-		58.91
			Synthetic oil, per barrel		-		92.77		-		-		-		-		92.77
		Average production costs, per oil-equivalent barrel - total			11.68		26.94		10.34		13.35		3.74		12.11		9.91
		Average production costs, per barrel - bitumen			-		23.71		-		-		-		-		23.71
		Average production costs, per barrel - synthetic oil			-		47.45		-		-		-		-		47.45

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
During 2011	*(dollars per unit)*						
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	98.33	104.59	109.48	110.84	107.64	115.55	107.25
NGL, per barrel	62.48	65.71	66.80	78.20	44.16	59.44	60.15
Natural gas, per thousand cubic feet	3.45	3.29	9.32	2.83	3.37	3.98	4.65
Bitumen, per barrel	-	64.65	-	-	-	-	64.65
Synthetic oil, per barrel	-	102.80	-	-	-	-	102.80
Average production costs, per oil-equivalent barrel - total	11.14	23.58	13.58	14.04	6.58	12.85	12.33
Average production costs, per barrel - bitumen	-	19.80	-	-	-	-	19.80
Average production costs, per barrel - synthetic oil	-	47.68	-	-	-	-	47.68
Equity Companies							
Average production prices							
Crude oil, per barrel	105.00	-	103.23	-	105.87	-	105.71
NGL, per barrel	77.84	-	-	-	69.65	-	69.82
Natural gas, per thousand cubic feet	5.08	-	8.61	-	7.78	-	8.08
Average production costs, per oil-equivalent barrel - total	19.96	-	2.92	-	1.09	-	2.45
Total							
Average production prices							
Crude oil, per barrel	99.57	104.59	109.33	110.84	106.72	115.55	106.89
NGL, per barrel	62.75	65.71	66.80	78.20	58.33	59.44	62.42
Natural gas, per thousand cubic	3.45	3.29	8.96	2.83	6.14	3.98	5.93

			feet															
			Bitumen, per barrel		-		64.65		-		-		-		-		64.65
			Synthetic oil, per barrel		-		102.80		-		-		-		-		102.80
		Average production costs, per oil-equivalent barrel - total			11.68		23.58		9.85		14.04		3.41		12.85		9.45
		Average production costs, per barrel - bitumen			-		19.80		-		-		-		-		19.80
		Average production costs, per barrel - synthetic oil			-		47.68		-		-		-		-		47.68

Average production 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 oil and gas production table in section 3.A. The volumes of natural gas used in the calculation are the production volumes of natural gas available for sale and are also shown in section 3.A. The natural gas available for sale volumes 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. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

					2013		2012		2011
Net Productive Exploratory Wells Drilled									
	Consolidated Subsidiaries								
		United States			8		7		12
		Canada/South America			4		2		6
		Europe			-		1		1
		Africa			2		2		1
		Asia			-		1		2
		Australia/Oceania			-		2		1
			Total Consolidated Subsidiaries		14		15		23
	Equity Companies								
		United States			-		-		1
		Europe			1		1		1
		Asia			1		-		-
			Total Equity Companies		2		1		2
Total productive exploratory wells drilled					16		16		25
Net Dry Exploratory Wells Drilled									
	Consolidated Subsidiaries								
		United States			2		2		2
		Canada/South America			4		-		-
		Europe			1		2		4
		Africa			-		-		-
		Asia			-		2		5
		Australia/Oceania			-		1		-
			Total Consolidated Subsidiaries		7		7		11
	Equity Companies								
		United States			1		-		-
		Europe			-		1		-
		Asia			-		-		-
			Total Equity Companies		1		1		-
Total dry exploratory wells drilled					8		8		11

					2013		2012		2011
Net Productive Development Wells Drilled									
	Consolidated Subsidiaries								
		United States			755		867		1,069
		Canada/South America			201		73		154
		Europe			13		10		7
		Africa			33		39		44
		Asia			30		28		30
		Australia/Oceania			3		-		-
			Total Consolidated Subsidiaries		1,035		1,017		1,304
	Equity Companies								
		United States			328		282		236
		Europe			2		4		10
		Asia			8		7		4
			Total Equity Companies		338		293		250
Total productive development wells drilled					1,373		1,310		1,554
Net Dry Development Wells Drilled									
	Consolidated Subsidiaries								
		United States			5		5		14
		Canada/South America			-		-		-
		Europe			2		1		1
		Africa			-		-		-
		Asia			-		2		1
		Australia/Oceania			-		-		-
			Total Consolidated Subsidiaries		7		8		16
	Equity Companies								
		United States			-		-		-
		Europe			1		-		-
		Asia			-		-		-
			Total Equity Companies		1		-		-
Total dry development wells drilled					8		8		16
	Total number of net wells drilled				1,405		1,342		1,606

B. Exploratory and Development Activities Regarding Oil and Gas Resources Extracted by Mining Technologies

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 then upgrade it to produce a high-quality, light (32 degrees API), sweet, 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. In 2013, the company's share of net production of synthetic crude oil was about 65 thousand barrels per day and share of net acreage was about 63 thousand acres in the Athabasca oil sands deposit.

Kearl Project. The Kearl project is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen. Imperial Oil Limited holds a 70.96 percent interest in the joint venture and ExxonMobil Canada Properties holds the other 29.04 percent. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited and a 100 percent interest in ExxonMobil Canada Properties. Kearl is comprised of six oil sands leases covering about 48 thousand acres in the Athabasca oil sands deposit.

The Kearl project is located approximately 40 miles north of Fort McMurray, Alberta, Canada. Bitumen is extracted from oil sands produced from open-pit mining operations, and processed through a bitumen extraction and froth treatment train. The product, a blend of bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline. Production from the initial development began in April 2013 and production ramp-up continued throughout the remainder of the year. During 2013, average net production at Kearl was 21 thousand barrels per day. The Kearl Expansion project was 72 percent complete at the end of 2013.

5. Present Activities

A. Wells Drilling

				Year-End 2013				Year-End 2012		
				Gross		Net		Gross		Net
Wells Drilling										
	Consolidated Subsidiaries									
		United States		1,199		480		1,099		503
		Canada/South America		107		95		138		118
		Europe		29		10		26		10
		Africa		38		11		33		10
		Asia		112		32		108		61
		Australia/Oceania		18		5		23		6
			Total Consolidated Subsidiaries	1,503		633		1,427		708
	Equity Companies									
		United States		9		4		17		4

		Europe		8		3		9		3
		Asia		11		1		19		2
			Total Equity Companies	28		8		45		9
Total gross and net wells drilling				1,531		641		1,472		717

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2013 acreage holdings totaled 15.1 million net acres, of which 2.0 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During 2013, 1080.3 net exploration and development wells were completed in the inland lower 48 states. Development activities focused on the Bakken oil play in North Dakota and Montana, the San Joaquin Basin of California, the Woodford and Caney Shales in the Ardmore, Marietta and Arkoma basins of Oklahoma, the Permian Basin of West Texas and New Mexico, the Marcellus Shale of Pennsylvania and West Virginia, the Haynesville Shale of Texas and Louisiana, the Barnett Shale of North Texas, and the Fayetteville Shale of Arkansas.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2013 was 1.9 million acres. A total of 2.5 net exploration and development wells were completed during the year. Development activities continued on the deepwater Hadrian South project and the non-operated Lucius project. The Heidelberg and Julia Phase 1 projects were funded in 2013.

Participation in Alaska production and development continued with a total of 17.1 net development wells completed. Development activities continued on the Point Thomson project.

CANADA / SOUTH AMERICA

Canada

Oil and Gas Operations: ExxonMobil's year-end 2013 acreage holdings totaled 5.6 million net acres, of which 1.0 million net acres were offshore. A total of 86.2 net exploration and development wells were completed during the year. Celtic Exploration Ltd. was acquired in 2013.

In Situ Bitumen Operations: ExxonMobil's year-end 2013 in situ bitumen acreage holdings totaled 0.7 million net onshore acres. A total of 120.0 net development wells were completed during the year. In 2013, ExxonMobil acquired an interest in the Clyden oil sands lease.

Argentina

ExxonMobil’s net acreage totaled 0.9 million onshore acres at year-end 2013, and there were 2.0 net exploration and development wells completed during the year.

Venezuela

ExxonMobil’s acreage holdings and assets were expropriated in 2007. Refer to the relevant portion of “Note 16: Litigation and Other Contingencies” of the Financial Section of this report for additional information.

EUROPE

Germany

A total of 4.9 million net onshore acres and 0.1 million net offshore acres were held by ExxonMobil at year-end 2013, with 5.3 net exploration and development wells completed during the year.

Netherlands

ExxonMobil’s net interest in licenses totaled approximately 1.5 million acres at year-end 2013, of which 1.2 million acres are onshore. A total of 4.2 net exploration and development wells were completed during the year.

Norway

ExxonMobil's net interest in licenses at year-end 2013 totaled approximately 0.7 million acres, all offshore. A total of 7.5 net exploration and development wells were completed in 2013.

United Kingdom

ExxonMobil’s net interest in licenses at year-end 2013 totaled approximately 0.4 million acres, all offshore. A total of 2.7 net development wells were completed during the year.

AFRICA

Angola

ExxonMobil's year-end 2013 acreage holdings totaled 0.4 million net offshore acres and 3.4 net development wells were completed during the year. On Block 15, project activities are under way at Kizomba Satellites Phase 2. On the non-operated Block 17, work continued on the Cravo-Lirio-Orquidea-Violeta project.

Chad

ExxonMobil's net year-end 2013 acreage holdings consisted of 46 thousand onshore acres, with 22.0 net development wells completed during the year.

Equatorial Guinea

ExxonMobil's acreage totaled 0.1 million net offshore acres at year-end 2013.

Nigeria

ExxonMobil's net acreage totaled 0.9 million offshore acres at year-end 2013, with 8.2 net exploration and development wells completed during the year. In 2013, ExxonMobil continued development drilling on the Satellite Field Development Phase 1 and the deepwater Usan projects. The Erha North Phase 2 deepwater project was funded in 2013.

ASIA

Azerbaijan

At year-end 2013, ExxonMobil's net acreage totaled 9 thousand offshore acres. A total of 0.7 net development wells were completed during the year. Work continued on the Chirag Oil project.

Indonesia

At year-end 2013, ExxonMobil had 2.3 million net acres, 1.3 million net acres offshore and 1.0 million net acres onshore. There was 0.4 net exploration well completed during the year.

Iraq

At year-end 2013, ExxonMobil's onshore acreage was 0.9 million net acres. A total of 23.2 net development wells were completed at the West Qurna Phase I oil field during the year. Field rehabilitation activities continued during 2013, and across the life of this project will include drilling of new wells, working over of existing wells, and optimization and debottlenecking of existing facilities. ExxonMobil sold a partial interest in West Qurna Phase I in 2013. In the Kurdistan Region of Iraq, ExxonMobil initiated a seismic program and exploration drilling in 2013.

Kazakhstan

ExxonMobil's net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2013. A total of 1.3 net development wells were completed during 2013. Working with our partners, construction of the initial phase of the Kashagan field continued, and the project started up in 2013.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.4 million net acres offshore at year-end 2013. During the year, a total of 5.0 net development wells were completed. Development activities continued on the Tapis and Damar projects and the Telok project started up in 2013.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil's net acreage totaled 65 thousand acres offshore at year-end 2013. During the year, a total of 0.7 net development wells were completed. ExxonMobil participated in 61.8 million tonnes per year gross liquefied natural gas capacity and 2.0 billion cubic feet per day of flowing gas capacity at year end. Development activities continued on the Barzan project.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 2013.

Russia

ExxonMobil’s net acreage holdings in Sakhalin at year-end 2013 were 85 thousand acres, all offshore. A total of 0.9 net development wells were completed. Development activities continued on the Arkutun-Dagi project during 2013.

At year-end 2013, ExxonMobil’s net acreage in the Rosneft joint venture agreements for the Kara and Black Seas was 11.3 million acres, all offshore. ExxonMobil and Rosneft formed a joint venture to evaluate the development of tight-oil reserves in western Siberia in 2013.

Thailand

ExxonMobil’s net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2013.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2013. The Upper Zakum 750 project was funded in 2013.

ExxonMobil's net acreage in the Abu Dhabi onshore oil concession was 0.5 million acres at year-end 2013, of which 0.4 million acres are onshore. During the year, a total of 6.7 net exploration and development wells were completed. The onshore oil concession expired in January 2014.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's year-end 2013 acreage holdings totaled 1.7 million net acres, of which 1.6 million net acres were offshore. During the year, a total of 1.9 net exploration and development wells were completed. The Kipper Tuna and Turrum projects started up during 2013.

Project construction activity for the co-venturer operated Gorgon liquefied natural gas (LNG) project progressed in 2013. The project consists of a subsea infrastructure for offshore production and transportation of the gas, and a 15.6 million tonnes per year LNG facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia.

Papua New Guinea

A total of 1.1 million net onshore acres were held by ExxonMobil at year-end 2013, with 1.3 net development wells completed during the year. Work continued on the Papua New Guinea (PNG) LNG project. The project consists of conditioning facilities in the southern PNG Highlands, a 6.9 million tonnes per year LNG facility near Port Moresby and approximately 434 miles of onshore and offshore pipelines.

WORLDWIDE EXPLORATION

At year-end 2013, exploration activities were under way in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 29.1 million net acres were held at year-end 2013, and 1.4 net exploration wells were completed during the year in these countries.

6. Delivery Commitments

ExxonMobil sells crude oil and natural gas from its producing operations under a variety of contractual obligations, some of which may specify the delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be a combination of our own production and the spot market. Worldwide, we are contractually committed to deliver approximately 2,800 billion cubic feet of natural gas for the period from 2014 through 2016. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will be fulfilled with production from our proved undeveloped reserves and spot market purchases as necessary.

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7. Oil and Gas Properties, Wells, Operations and Acreage

A. Gross and Net Productive Wells

	Year-End 2013				Year-End 2012			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	23,395	8,487	38,392	23,839	22,690	8,155	39,720	24,197
Canada/South America	5,486	4,990	4,478	1,762	5,283	4,825	4,271	1,584
Europe	1,254	352	649	269	1,255	346	622	258
Africa	1,186	472	16	6	1,231	491	11	4
Asia	756	270	207	151	792	370	204	150
Australia/Oceania	661	147	38	19	676	152	40	20
Total Consolidated Subsidiaries	32,738	14,718	43,780	26,046	31,927	14,339	44,868	26,213
Equity Companies								
United States	14,362	5,529	4,369	496	12,777	5,286	2,138	120
Europe	49	17	555	173	71	27	585	185
Asia	1,329	143	122	29	1,200	129	121	29
Total Equity Companies	15,740	5,689	5,046	698	14,048	5,442	2,844	334
Total gross and net productive wells	48,478	20,407	48,826	26,744	45,975	19,781	47,712	26,547

There were 37,661 gross and 31,823 net operated wells at year-end 2013 and 37,228 gross and 31,264 net operated wells at year-end 2012. The number of wells with multiple completions was 1,531 gross in 2013 and 1,647 gross in 2012.

Note: Year-end 2012 well counts for gross and net gas wells in Canada/South America were restated.

B. Gross and Net Developed Acreage

	Year-End 2013		Year-End 2012	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	16,504	10,061	16,444	10,164
Canada/South America *(1)*	4,421	2,041	4,545	1,940
Europe	3,355	1,511	3,382	1,515
Africa	2,105	780	2,105	780
Asia	1,828	557	1,322	525
Australia/Oceania	2,123	758	2,018	719
Total Consolidated Subsidiaries	30,336	15,708	29,816	15,643
Equity Companies				
United States	968	241	496	202
Europe	4,341	1,356	4,344	1,357
Asia	5,731	640	5,731	640
Total Equity Companies	11,040	2,237	10,571	2,199
Total gross and net developed acreage	41,376	17,945	40,387	17,842

(1) Includes developed acreage in South America of 214 gross and 109 net thousands of acres for 2013 and 618 gross and 202 net thousand acres for 2012.

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

C. Gross and Net Undeveloped Acreage

	Year-End 2013		Year-End 2012	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	7,645	4,722	8,517	5,077
Canada/South America *(1)*	16,319	9,232	16,669	8,700
Europe	13,461	6,585	35,928	16,123
Africa	20,877	13,446	12,005	7,707
Asia	18,639	13,979	24,346	20,239
Australia/Oceania	7,144	1,991	7,460	1,991

			Total Consolidated Subsidiaries	84,085		49,955		104,925		59,837
	Equity Companies									
		United States		363		121		351		108
		Europe		-		-		-		-
		Asia		34,147		11,352		73		5
			Total Equity Companies	34,510		11,473		424		113
Total gross and net undeveloped acreage				118,595		61,428		105,349		59,950

(1) Includes undeveloped acreage in South America of 8,795 gross and 4,674 net thousands of acres for 2013 and 8,412 gross and 4,484 net thousands of acres for 2012.

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. The scheduled expiration of leases and concessions for undeveloped acreage over the next three years is not expected to have a material adverse impact on the Corporation.

D. Summary of Acreage Terms

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. Under certain circumstances, a lease may be held beyond its exploration term even if production has not commenced. 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 licenses or leases in onshore areas are acquired for varying periods of time with renewals or extensions possible. These licenses or leases entitle the holder to continue existing licenses or leases upon completing specified work. In general, these license and lease agreements are held as long as there is production on the licenses and leases. Exploration licenses in offshore eastern Canada and the Beaufort Sea are held by work commitments of various amounts and rentals. They are valid for a maximum term of nine years. Production licenses in the offshore are valid for 25 years, with rights of extension for continued production. Significant discovery licenses in the offshore, relating to currently undeveloped discoveries, do not have a definite term.

Argentina

The federal 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. Argentine provinces are entitled to modify the concession terms granted within their territories. The concession terms of the exploration permits granted by Neuquen Province are up to six years for the initial exploration period, up to four years for the second exploration period and up to three years for the third exploration period depending on the classification of the area. An extension after the third exploration period is possible for up to one year.

EUROPE

Germany

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

Netherlands

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

perform the activities for which the license is issued. License conditions are stipulated in the license and are based on 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. At the end of any such 40-year term, licenses may continue in producing areas until cessation of production; or licenses may continue in development areas for periods agreed on a case-by-case basis until they become producing areas; or licenses terminate in all other areas. The licensing regime was last updated in 2002, and the majority of licenses issued have an initial term of four years with a second term extension of four years and a final term of 18 years with 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.

Chad

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

Equatorial Guinea

Exploration and production activities are governed by production sharing contracts negotiated with the State Ministry of Mines, Industry and Energy. The exploration periods are for 10 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. Under the Hydrocarbons Law enacted in 2006, the exploration terms for new production sharing contracts are 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 have been renewed, effective December 1, 2008, for a further period of 20 years, with a further renewal option of 20 years. 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

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.

Indonesia

Exploration and production activities in Indonesia are generally governed by cooperation contracts, usually in the form of a production sharing contract (PSC), negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. In 2012, Indonesia's Constitutional Court ruled certain articles of law relating to BPMIGAS to be unconstitutional, but stated that all existing PSCs signed with BPMIGAS should remain in force until their expiry, and the functions and duties previously performed by BPMIGAS are to be carried out by the relevant Ministry of the Government of Indonesia until the promulgation of a new oil and gas law. The current PSCs have an exploration period of six years, which can be extended up to 10 years, and an exploitation period of 20 years. PSCs generally require the contractor to relinquish 10 percent to 20 percent of the contract area after three years and generally allow the contractor to retain no more than 50 percent to 80 percent of the original contract area after six years, depending on the acreage and terms.

Iraq

Development and production activities in the state-owned oil and gas fields are governed by contracts with regional oil companies of the Iraqi Ministry of Oil. An ExxonMobil affiliate entered into a contract with South Oil Company of the Iraqi Ministry of Oil for the rights to participate in the development and production activities of the West Qurna Phase I oil and gas field effective March 1, 2010. The term of the contract is 20 years with the right to extend for five years. The contract provides for cost recovery plus per-barrel fees for incremental production above specified levels.

Exploration and production activities in the Kurdistan Region of Iraq are governed by production sharing contracts negotiated with the regional government of Kurdistan in 2011. The exploration term is for five years with the possibility of two-year extensions. The production period is 20 years with the right to extend for five years.

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 is 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.

Malaysia

Exploration and production activities are governed by production sharing contracts (PSCs) negotiated with the national oil company. The more recent PSCs governing exploration and production activities 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.

In 2008, the Company reached agreement with the national oil company for a new PSC, which was subsequently signed in 2009. Under the new PSC, from 2008 until March 31, 2012, the Company was entitled to undertake new development and production activities in oil fields under an existing PSC, subject to new minimum work and spending commitments, including an enhanced oil recovery project in one of the oil fields. When the existing PSC expired on March 31, 2012, the producing fields covered by the existing PSC automatically became part of the new PSC, which has a 25-year duration from April 2008.

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

The Jannah production sharing agreement has a development period extending 20 years from first commercial declaration, which was made in June 1995.

Russia

Terms for ExxonMobil's Sakhalin 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 ten-year increments as specified in the PSA.

Exploration and production activities in the Kara and Black Seas are governed by joint venture agreements concluded with Rosneft in 2013 that cover certain of Rosneft's offshore licenses. The Kara Sea licenses extend through 2040 and include an exploration period through 2020, development plan submission within eight years of a discovery and development activities within five years of plan approval. The Black Sea exploration license extends through 2017 and a discovery is the basis for obtaining a license for production.

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 oil fields in the Emirate of Abu Dhabi were governed by a 75-year oil concession agreement executed in 1939, which expired in January 2014. An interest in the development and production activities of the Upper Zakum field, a major offshore field, was acquired effective as of January 2006, for a term expiring March 2026, and in 2013 the governing agreements were extended to 2041.

AUSTRALIA/OCEANIA

Australia

Exploration and production activities conducted offshore in Commonwealth waters are governed by Federal legislation. Exploration permits are granted for an initial term of six years with two possible five-year renewal periods. 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. Effective from July 1998, new production licenses are granted "indefinitely". In each case, a production license may be terminated if no production operations have been carried on for five years.

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. 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.

Information with regard to the Downstream segment follows:

ExxonMobil's Downstream segment manufactures and sells petroleum products. The refining and supply operations encompass a global network of manufacturing plants, transportation systems, and distribution centers that provide a range of fuels, lubricants and other products and feedstocks to our customers around the world.

Refining Capacity At Year-End 2013 *(1)*

				ExxonMobil Share KBD *(2)*		ExxonMobil Interest %	
United States							
	Torrance		California	150		100	
	Joliet		Illinois	238		100	
	Baton Rouge		Louisiana	502		100	
	Baytown		Texas	561		100	
	Beaumont		Texas	345		100	
	Other (2 refineries)			155			
		Total United States		1,951			
Canada							
	Strathcona		Alberta	189		69.6	
	Nanticoke		Ontario	113		69.6	
	Sarnia		Ontario	119		69.6	
		Total Canada		421			
Europe							
	Antwerp		Belgium	307		100	
	Fos-sur-Mer		France	133		82.9	
	Gravenchon		France	236		82.9	
	Karlsruhe		Germany	78		25	
	Augusta		Italy	198		100	
	Trecate		Italy	127		75.5	
	Rotterdam		Netherlands	191		100	
	Slagen		Norway	116		100	
	Fawley		United Kingdom	260		100	
		Total Europe		1,646			
Asia Pacific							
	Jurong/PAC		Singapore	592		100	
	Sriracha		Thailand	167		66	
	Other (7 refineries)			297			

		Total Asia Pacific		1,056			
Other Non-U.S.							
	Yanbu		Saudi Arabia	200		50	
	Laffan		Qatar	15		10	
	Fort-de-France		Martinique	2		14.5	
		Total Other Non-U.S.		217			
Total Worldwide				5,291			

(1) Capacity data is based on 100 percent of rated refinery process unit stream-day capacities under normal operating conditions, less the impact of shutdowns for regular repair and maintenance activities, averaged over an extended period of time.

(2) Thousands of barrels per day (KBD). ExxonMobil share reflects 100 percent of atmospheric distillation capacity in operations of ExxonMobil and majority-owned subsidiaries. For companies owned 50 percent or less, ExxonMobil share is the greater of ExxonMobil's equity interest or that portion of distillation capacity normally available to ExxonMobil.

The marketing operations sell products and services throughout the world through our *Exxon*, *Esso* and *Mobil* brands.

Retail Sites At Year-End 2013

	United States				
		Owned/leased		-	
		Distributors/resellers		9,196	
			Total United States	9,196	
	Canada				
		Owned/leased		472	
		Distributors/resellers		1,259	
			Total Canada	1,731	
	Europe				
		Owned/leased		3,445	
		Distributors/resellers		2,812	
			Total Europe	6,257	
	Asia Pacific				
		Owned/leased		666	
		Distributors/resellers		313	
			Total Asia Pacific	979	
	Latin America				
		Owned/leased		53	
		Distributors/resellers		705	
			Total Latin America	758	
	Middle East/Africa				
		Owned/leased		436	
		Distributors/resellers		197	
			Total Middle East/Africa	633	
	Worldwide				
		Owned/leased		5,072	
		Distributors/resellers		14,482	
			Total Worldwide	19,554	

Information with regard to the Chemical segment follows:

ExxonMobil's Chemical segment manufactures and sells petrochemicals. The Chemical business supplies olefins, polyolefins, aromatics, and a wide variety of other petrochemicals.

Chemical Complex Capacity At Year-End 2013 *(1)(2)*

													ExxonMobil
				Ethylene		Polyethylene		Polypropylene		Paraxylene		Interest %	
North America													
	Baton Rouge		Louisiana	1.0		1.3		0.4		-		100	
	Baytown		Texas	2.2		-		0.7		0.6		100	
	Beaumont		Texas	0.9		1.0		-		0.3		100	
	Mont Belvieu		Texas	-		1.0		-		-		100	
	Sarnia		Ontario	0.3		0.5		-		-		69.6	
		Total North America		4.4		3.8		1.1		0.9			
Europe													
	Antwerp		Belgium	-		0.4		-		-		100	
	Fife		United Kingdom	0.4		-		-		-		50	
	Meerhout		Belgium	-		0.5		-		-		100	
	Gravenchon		France	0.4		0.4		0.3		-		100	
	Rotterdam		Netherlands	-		-		-		0.7		100	
		Total Europe		0.8		1.3		0.3		0.7			
Middle East													
	Al Jubail		Saudi Arabia	0.6		0.7		-		-		50	
	Yanbu		Saudi Arabia	1.0		0.7		0.2		-		50	
		Total Middle East		1.6		1.4		0.2		-			
Asia Pacific													
	Fujian		China	0.2		0.2		0.1		0.2		25	
	Kawasaki		Japan	0.1		-		-		-		22	
	Singapore		Singapore	1.9		1.9		0.9		0.9		100	
	Sriracha		Thailand	-		-		-		0.5		66	
		Total Asia Pacific		2.2		2.1		1.0		1.6			
All Other				-		-		-		0.2			
Total Worldwide				9.0		8.6		2.6		3.4			

(1) Capacity for ethylene, polyethylene, polypropylene and paraxylene in millions of metric tons per year.

(2) Capacity reflects 100 percent for operations of ExxonMobil and majority-owned subsidiaries. For companies owned 50 percent or less, capacity is ExxonMobil's interest.

Item 3. Legal Proceedings

In November 2013, the Texas Commission on Environmental Quality (TCEQ) contacted Exxon Mobil Corporation (the "Corporation") concerning alleged violations of the Texas Clean Air Act, implementing regulations and the applicable new source review permit in connection with exceedances of volatile organic compound emissions from Tank 22 at the Corporation's King Ranch Gas Plant. TCEQ is seeking a civil penalty in excess of $100,000 along with certain corrective action. The Corporation is working with TCEQ to resolve the matter.

Regarding the June 27, 2013, Administrative Consent Agreement between the North Dakota Department of Health (NDDOH) and XTO Energy Inc. (XTO) resolving the air enforcement matter previously reported in the Corporation's Forms 10-Q for the first and second quarters of 2013, pursuant to the terms of the Administrative Consent Agreement, during the fourth quarter of 2013, XTO provided the NDDOH with an updated list of well sites on newly acquired assets with air emission control issues. On November 12, 2013, XTO paid an additional penalty assessment of $183,400 with respect to those sites.

Regarding the criminal charges filed against XTO by the Pennsylvania Attorney General's Office pertaining to XTO's Marquardt Well Site in Penn Township, Pennsylvania, reported most recently in the Corporation's Form 10-Q for the third quarter of 2013, on January 2, 2014, a Pennsylvania state magistrate ruled that the Attorney General's Office had presented sufficient evidence for the charges to proceed to trial in the Pennsylvania Court of Common Pleas. At the trial, XTO will have an opportunity to present its full defense to the charges, which it believes are unwarranted.

Regarding the settlement of matters between the Louisiana Department of Environmental Quality (LDEQ) and ExxonMobil Refining and Supply Company and ExxonMobil Chemical Company, both divisions of the Corporation, involving ExxonMobil facilities in Baton Rouge, Louisiana, last reported in the Corporation's Form 10-Q for the third quarter of 2013, during the fourth quarter of 2013, the public comment period on the proposed settlement ended, and the Louisiana Attorney General issued his concurrence with regard to the settlement terms. The parties executed the final documents in January 2014, thereby resolving the matters covered by the settlement. The settlement terms include payment of a $300,000 penalty, an agreement to complete certain on-site improvement projects valued at $1,000,000, Beneficial Environmental Projects valued at $1,029,000 and a Stipulated Penalty Agreement to address any future environmental non-compliance.

On December 11, 2013, the TCEQ Commissioner's Court accepted and signed the Agreed Order settling the enforcement action, including a penalty of $126,250, concerning emission events at ExxonMobil Oil Corporation's (EMOC) Beaumont Refinery previously reported in the Corporation's Forms 10-Q for the first and third quarters of 2013.

Regarding the complaint against EMOC filed by the Attorney General for the State of New York alleging contamination of soil and groundwater at a former Mobil petroleum terminal at Lighthouse Point in Ogdensburg, New York, previously reported in the Corporation's Form 10-Q for the third quarter of 2011, the parties reached a settlement agreement that was entered into the court record on November 14, 2013. On December 16, 2013, the parties signed the agreement, and EMOC made a payment to the State of $8.05 million, pursuant to the agreement's terms.

Refer to the relevant portions of "Note 16: Litigation and Other Contingencies" of the Financial Section of this report for additional information on legal proceedings.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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

Rex W. Tillerson *Chairman of the Board*

Held current title since: January 1, 2006 Age: 61
Mr. Rex W. Tillerson became a Director and President of Exxon Mobil Corporation on March 1, 2004. He became Chairman of the Board and Chief Executive Officer on January 1, 2006. He still holds these positions as of this filing date.

Mark W. Albers *Senior Vice President*

Held current title since: April 1, 2007 Age: 57
Mr. Mark W. Albers became Senior Vice President of Exxon Mobil Corporation on April 1, 2007, a position he still holds as of this filing date.

Michael J. Dolan *Senior Vice President*

Held current title since: April 1, 2008 Age: 60
Mr. Michael J. Dolan became Senior Vice President of Exxon Mobil Corporation on April 1, 2008, a position he still holds as of this filing date.

Andrew P. Swiger *Senior Vice President*

Held current title since: April 1, 2009 Age: 57
Mr. Andrew P. Swiger was President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation October 1, 2006 – March 31, 2009. He became Senior Vice President of Exxon Mobil Corporation on April 1, 2009, a position he still holds as of this filing date.

S. Jack Balagia *Vice President and General Counsel*

Held current title since: March 1, 2010 Age: 62
Mr. S. Jack Balagia was Assistant General Counsel of Exxon Mobil Corporation April 1, 2004 – March 1, 2010. He became Vice President and General Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

Randy J. Cleveland *President, XTO Energy Inc., a subsidiary of the Corporation*

Held current title since: June 1, 2013 Age: 52

Mr. Randy J. Cleveland was Production Manager, U.S. Production, ExxonMobil Production Company April 1, 2006 – April 30, 2009. He was Planning & Commercial Manager, ExxonMobil Production Company May 1, 2009 – June 24, 2010. He was Vice President, XTO Integration, XTO Energy Inc. June 25, 2010 – January 31, 2012. He was Executive Vice President, XTO Energy Inc. February 1, 2012 – May 31, 2013. He became President of XTO Energy Inc. on June 1, 2013, a position he still holds as of this filing date.

William M. Colton *Vice President – Corporate Strategic Planning*

Held current title since: February 1, 2009 Age: 60

Mr. William M. Colton was Assistant Treasurer of Exxon Mobil Corporation January 25, 2006 – January 31, 2009. He became Vice President – Corporate Strategic Planning of Exxon Mobil Corporation on February 1, 2009, a position he still holds as of this filing date.

Michael G. Cousins *Vice President*

Held current title since: March 1, 2013 Age: 53

Mr. Michael G. Cousins was Planning Manager, ExxonMobil Exploration Company April 1, 2008 – May 31, 2009. He was Vice President, Asia Pacific/Middle East, ExxonMobil Exploration Company June 1, 2009 – March 31, 2012. He was Executive Assistant to the Chairman, Exxon Mobil Corporation April 1, 2012 – February 28, 2013. He became President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Neil W. Duffin *President, ExxonMobil Development Company*

Held current title since: April 13, 2007 Age: 57

Mr. Neil W. Duffin became President of ExxonMobil Development Company on April 13, 2007, a position he still holds as of this filing date.

Robert S. Franklin *Vice President*

Held current title since: May 1, 2009 Age: 56

Mr. Robert S. Franklin was Vice President, Europe/Russia/Caspian of ExxonMobil Production Company April 1, 2008 – May 1, 2009. He was Vice President of Exxon Mobil Corporation and President, ExxonMobil Upstream Ventures May 1, 2009 – February 28, 2013. He became President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Stephen M. Greenlee *Vice President*

Held current title since: September 1, 2010 Age: 56

Mr. Stephen M. Greenlee was Vice President of ExxonMobil Exploration Company June 1, 2004 – June 1, 2009. He was President of ExxonMobil Upstream Research Company June 1, 2009 – August 31, 2010. He became President of ExxonMobil Exploration Company and Vice President of Exxon Mobil Corporation on September 1, 2010, positions he still holds as of this filing date.

Alan J. Kelly *Vice President*

Held current title since: December 1, 2007 Age: 56

Mr. Alan J. Kelly became President of ExxonMobil Lubricants & Petroleum Specialties Company and Vice President of Exxon Mobil Corporation on December 1, 2007. On February 1, 2012, the businesses of ExxonMobil Lubricants & Petroleum Specialties Company and ExxonMobil Fuels Marketing Company were consolidated and Mr. Kelly became President of the combined ExxonMobil Fuels, Lubricants & Specialties Marketing Company and Vice President of Exxon Mobil Corporation, positions he still holds as of this filing date.

Patrick T. Mulva *Vice President and Controller*

Held current title since: February 1, 2002 (Vice President) Age: 62

July 1, 2004 (Controller)

Mr. Patrick T. Mulva became Vice President of Exxon Mobil Corporation on February 1, 2002 and Controller of Exxon Mobil Corporation on July 1, 2004, positions he still holds as of this filing date.

Stephen D. Pryor *Vice President*

Held current title since: December 1, 2004 Age: 64

Mr. Stephen D. Pryor became Vice President of Exxon Mobil Corporation on December 1, 2004 and President of ExxonMobil Chemical Company on April 1, 2008, positions he still holds as of this filing date.

David S. Rosenthal *Vice President - Investor Relations and Secretary*

Held current title since: October 1, 2008 Age: 57
Mr. David S. Rosenthal became Vice President – Investor Relations and Secretary of Exxon Mobil Corporation on October 1, 2008, positions he still holds as of this filing date.

Robert N. Schleckser *Vice President and Treasurer*

Held current title since: May 1, 2011 Age: 57
Mr. Robert N. Schleckser was Downstream Treasurer, Downstream Business Services May 1, 2005 – January 31, 2009. He was Assistant Treasurer of Exxon Mobil Corporation February 1, 2009 – April 30, 2011. He became Vice President and Treasurer of Exxon Mobil Corporation on May 1, 2011, positions he still holds as of this filing date.

James M. Spellings, Jr. *Vice President and General Tax Counsel*

Held current title since: March 1, 2010 Age: 52
Mr. James M. Spellings, Jr. was Associate General Tax Counsel of Exxon Mobil Corporation April 1, 2007 – March 1, 2010. He became Vice President and General Tax Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

Thomas R. Walters *Vice President*

Held current title since: April 1, 2009 Age: 59
Mr. Thomas R. Walters was Executive Vice President of ExxonMobil Development Company April 13, 2007 – April 1, 2009. He was President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation April 1, 2009 – February 28, 2013. He became President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Darren W. Woods *Vice President*

Held current title since: August 1, 2012 Age: 49
Mr. Darren W. Woods was Director, Refining Europe/Africa/Middle East, ExxonMobil Refining & Supply Company February 1, 2008 – June 30, 2010. He was Vice President, Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2012. He became President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corporation on August 1, 2012, positions he still holds as of this filing date.

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

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PART II

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

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

	Issuer Purchases of Equity Securities for Quarter Ended December 31, 2013				
				Total Number of	
				Shares	
				Purchased as	Maximum Number
				Part of Publicly	of Shares that May
		Total Number of	Average Price	Announced	Yet Be Purchased
		Shares	Paid per	Plans or	Under the Plans or
Period		Purchased	Share	Programs	Programs
October 2013		12,589,049	87.12	12,589,049	
November 2013		13,152,312	93.69	13,152,312	
December 2013		10,025,720	97.08	10,025,720	
	Total	35,767,081	92.33	35,767,081	(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. In its most recent earnings release dated January 30, 2014, the Corporation stated that first quarter 2014 share purchases are continuing at a pace consistent with fourth quarter 2013 share reduction spending of $3 billion. 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.

Item 6. Selected Financial Data

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	420,836	451,509	467,029	370,125	301,500
(1) Sales-based taxes included	*30,589*	*32,409*	*33,503*	*28,547*	*25,936*

Net income attributable to ExxonMobil	32,580		44,880		41,060		30,460		19,280
Earnings per common share	7.37		9.70		8.43		6.24		3.99
Earnings per common share - assuming dilution	7.37		9.70		8.42		6.22		3.98
Cash dividends per common share	2.46		2.18		1.85		1.74		1.66
Total assets	346,808		333,795		331,052		302,510		233,323
Long-term debt	6,891		7,928		9,322		12,227		7,129

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 26, 2014, beginning with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing through "Note 19: 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, 2013. 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 criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2013, 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 2014 annual meeting of shareholders (the "2014 Proxy Statement"):

•	The section entitled "Election of Directors";
•	The portion entitled "Section 16(a) Beneficial Ownership Reporting Compliance" of the section entitled "Director and Executive Officer Stock Ownership";
•	The portions entitled "Director Qualifications" and "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 2014 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 sections "Director and Executive Officer Stock Ownership" and "Certain Beneficial Owners" of the registrant's 2014 Proxy Statement.

Equity Compensation Plan Information								
		(a)			***(b)***		***(c)***	
							Number of Securities	
					Weighted-		**Remaining Available**	
					Average		**for Future Issuance**	
		Number of Securities			**Exercise Price**		**Under Equity**	
		to be Issued Upon			**of Outstanding**		**Compensation**	
		Exercise of			**Options,**		**Plans [Excluding**	
		Outstanding Options,			**Warrants and**		**Securities Reflected**	
Plan Category		**Warrants and Rights**			**Rights**		**in Column (a)]**	
		17,358,275	*(1)(2)*		-		117,260,597	*(2)(3)(4)*

Equity compensation plans approved by security holders								
Equity compensation plans not approved by security holders		-			-		-	
	Total	17,358,275			-		117,260,597	

(1) The number of restricted stock units to be settled in shares.

(2) Does not include options that ExxonMobil assumed in the 2010 merger with XTO Energy Inc. At year-end 2013, the number of securities to be issued upon exercise of outstanding options under XTO Energy Inc. plans was 1,505,820, and the weighted-average exercise price of such options was $85.57. No additional awards may be made under those plans.

(3) Available shares can be granted in the form of restricted stock, options, or other stock-based awards. Includes 116,619,397 shares available for award under the 2003 Incentive Program and 641,200 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.

(4) 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 2,500 restricted shares each following year. While on the Board, each non-employee director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the shares. The restricted shares may be forfeited if the director leaves the Board early.

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

Incorporated by reference to the portions entitled “Related Person Transactions and Procedures” and “Director Independence” of the section entitled “Corporate Governance” of the registrant’s 2014 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Incorporated by reference to the portion entitled “Audit Committee” of the section entitled “Corporate Governance” and the section entitled “Ratification of Independent Auditors” of the registrant’s 2014 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.

FINANCIAL SECTION

TABLE OF CONTENTS

BUSINESS PROFILE

	Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
Financial	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	4,191	3,925	59,898	57,631	7.0	6.8	9,145	11,080
Non-U.S.	22,650	25,970	93,071	81,811	24.3	31.7	29,086	25,004
Total	26,841	29,895	152,969	139,442	17.5	21.4	38,231	36,084
Downstream								
United States	2,199	3,575	4,757	4,630	46.2	77.2	951	634
Non-U.S.	1,250	9,615	19,673	19,401	6.4	49.6	1,462	1,628
Total	3,449	13,190	24,430	24,031	14.1	54.9	2,413	2,262
Chemical								
United States	2,755	2,220	4,872	4,671	56.5	47.5	963	408
Non-U.S.	1,073	1,678	15,793	15,477	6.8	10.8	869	1,010
Total	3,828	3,898	20,665	20,148	18.5	19.3	1,832	1,418
Corporate and financing	(1,538)	(2,103)	(6,489)	(4,527)	-	-	13	35
Total	32,580	44,880	191,575	179,094	17.2	25.4	42,489	39,799

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

Operating	**2013**	**2012**		**2013**	**2012**
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	431	418	United States	1,819	1,816
Non-U.S.	1,771	1,767	Non-U.S.	2,766	3,198
Total	2,202	2,185	Total	4,585	5,014
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales		
United States	3,545	3,822	United States	2,609	2,569

	Non-U.S.	8,291		8,500			Non-U.S.	3,278		3,605
	Total	11,836		12,322			Total	5,887		6,174
	(thousands of oil-equivalent barrels daily)							*(thousands of metric tons)*		
Oil-equivalent production *(1)*		4,175		4,239		Chemical prime product sales *(2)*				
							United States	9,679		9,381
							Non-U.S.	14,384		14,776
							Total	24,063		24,157

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

(2) Prime product sales include ExxonMobil´s share of equity company volumes and finished-product transfers to the Downstream.

FINANCIAL SUMMARY

		2013	2012	2011	2010	2009
		(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*		420,836	451,509	467,029	370,125	301,500
Earnings						
	Upstream	26,841	29,895	34,439	24,097	17,107
	Downstream	3,449	13,190	4,459	3,567	1,781
	Chemical	3,828	3,898	4,383	4,913	2,309
	Corporate and financing	(1,538)	(2,103)	(2,221)	(2,117)	(1,917)
	Net income attributable to ExxonMobil	32,580	44,880	41,060	30,460	19,280
Earnings per common share		7.37	9.70	8.43	6.24	3.99
Earnings per common share – assuming dilution		7.37	9.70	8.42	6.22	3.98
Cash dividends per common share		2.46	2.18	1.85	1.74	1.66
Earnings to average ExxonMobil share of equity (percent)		19.2	28.0	27.3	23.7	17.3
Working capital		(12,416)	321	(4,542)	(3,649)	3,174
Ratio of current assets to current liabilities (times)		0.83	1.01	0.94	0.94	1.06
Additions to property, plant and equipment		37,741	35,179	33,638	74,156	22,491
Property, plant and equipment, less allowances		243,650	226,949	214,664	199,548	139,116
Total assets		346,808	333,795	331,052	302,510	233,323
Exploration expenses, including dry holes		1,976	1,840	2,081	2,144	2,021
Research and development costs		1,044	1,042	1,044	1,012	1,050
Long-term debt		6,891	7,928	9,322	12,227	7,129
Total debt		22,699	11,581	17,033	15,014	9,605
Fixed-charge coverage ratio (times)		55.7	62.4	53.4	42.2	25.8
Debt to capital (percent)		11.2	6.3	9.6	9.0	7.7
Net debt to capital (percent) *(2)*		9.1	1.2	2.6	4.5	(1.0)
ExxonMobil share of equity at year-end		174,003	165,863	154,396	146,839	110,569
ExxonMobil share of equity per common share		40.14	36.84	32.61	29.48	23.39
Weighted average number of common shares						

	outstanding (millions)		4,419		4,628		4,870		4,885		4,832
Number of regular employees at year-end (thousands) *(3)*			75.0		76.9		82.1		83.6		80.7
CORS employees not included above (thousands) *(4)*			9.8		11.1		17.0		20.1		22.0

(1) Sales and other operating revenue includes sales-based taxes of $30,589 million for 2013, $32,409 million for 2012, $33,503 million for 2011, $28,547 million for 2010 and $25,936 million for 2009.

(2) Debt net of cash, excluding restricted cash.

(3) 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.

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

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 associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments 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 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 proceeds associated with asset sales 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			**2013**		**2012**		**2011**
			(millions of dollars)				
Net cash provided by operating activities			44,914		56,170		55,345
Proceeds associated with sales of subsidiaries, property, plant and equipment,							
	and sales and returns of investments		2,707		7,655		11,133
	Cash flow from operations and asset sales		47,621		63,825		66,478

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 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			**2013**		**2012**		**2011**
			(millions of dollars)				
Business uses: asset and liability perspective							
Total assets			346,808		333,795		331,052
Less liabilities and noncontrolling interests share of assets and liabilities							
			(55,916)		(60,486)		(69,794)

	Total current liabilities excluding notes and loans payable					
	Total long-term liabilities excluding long-term debt		(87,698)		(90,068)	(83,481)
	Noncontrolling interests share of assets and liabilities		(8,935)		(6,235)	(7,314)
Add ExxonMobil share of debt-financed equity company net assets			6,109		5,775	4,943
	Total capital employed		200,368		182,781	175,406
Total corporate sources: debt and equity perspective						
Notes and loans payable			15,808		3,653	7,711
Long-term debt			6,891		7,928	9,322
ExxonMobil share of equity			174,003		165,863	154,396
Less noncontrolling interests share of total debt			(2,443)		(438)	(966)
Add ExxonMobil share of equity company debt			6,109		5,775	4,943
	Total capital employed		200,368		182,781	175,406

FREQUENTLY USED TERMS

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 attributable to ExxonMobil 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	**2013**	**2012**	**2011**
	(millions of dollars)		
Net income attributable to ExxonMobil	32,580	44,880	41,060
Financing costs (after tax)			
Gross third-party debt	(163)	(401)	(153)
ExxonMobil share of equity companies	(239)	(257)	(219)
All other financing costs – net	83	100	116
Total financing costs	(319)	(558)	(256)
Earnings excluding financing costs	32,899	45,438	41,316
Average capital employed	191,575	179,094	170,721
Return on average capital employed – corporate total	17.2%	25.4%	24.2%

QUARTERLY INFORMATION

	2013					2012				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
Production of crude oil	*(thousands of barrels daily)*									
and natural gas liquids,	2,193	2,182	2,199	2,235	2,202	2,214	2,208	2,116	2,203	2,185
synthetic oil and bitumen										
Refinery throughput	4,576	4,466	4,847	4,452	4,585	5,330	4,962	4,929	4,837	5,014
Petroleum product sales	5,755	5,765	6,031	5,994	5,887	6,316	6,171	6,105	6,108	6,174
Natural gas production	*(millions of cubic feet daily)*									
available for sale	13,213	11,354	10,914	11,887	11,836	14,036	11,661	11,061	12,541	12,322
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production *(1)*	4,395	4,074	4,018	4,216	4,175	4,553	4,152	3,960	4,293	4,239
	(thousands of metric tons)									
Chemical prime product sales	5,910	5,831	6,245	6,077	24,063	6,337	5,972	5,947	5,901	24,157
Summarized financial data										
Sales and other operating	*(millions of dollars)*									
revenue *(2)(3)*	103,378	103,050	108,390	106,018	420,836	118,961	112,398	110,989	109,161	451,509
Gross profit *(4)*	30,083	28,689	30,300	29,901	118,973	35,672	32,715	33,209	31,969	133,565
Net income attributable to										
ExxonMobil	9,500	6,860	7,870	8,350	32,580	9,450	15,910	9,570	9,950	44,880

Per share data		*(dollars per share)*									
Earnings per common share *(5)*	2.12	1.55	1.79	1.91	7.37		2.00	3.41	2.09	2.20	9.70
Earnings per common share											
– assuming dilution *(5)*	2.12	1.55	1.79	1.91	7.37		2.00	3.41	2.09	2.20	9.70
Dividends per common share	0.57	0.63	0.63	0.63	2.46		0.47	0.57	0.57	0.57	2.18
Common stock prices											
High	91.93	93.50	95.49	101.74	101.74		87.94	87.67	92.57	93.67	93.67
Low	86.59	85.02	85.61	84.79	84.79		83.19	77.13	82.83	84.70	77.13

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

(2) Prior periods' data has been reclassified in certain cases to conform to the 2013 presentation basis.

(3) Includes amounts for sales-based taxes.

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

(5) Computed using the average number of shares outstanding during each period. The sum of the four quarters may not add to the full year.

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 450,634 registered shareholders of ExxonMobil common stock at December 31, 2013. At January 31, 2014, the registered shareholders of ExxonMobil common stock numbered 449,312.

On January 29, 2014, the Corporation declared a $0.63 dividend per common share, payable March 10, 2014.

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

FUNCTIONAL EARNINGS				**2013**		**2012**		**2011**
				(millions of dollars, except per share amounts)				
Earnings (U.S. GAAP)								
Upstream								
	United States			4,191		3,925		5,096
	Non-U.S.			22,650		25,970		29,343
Downstream								
	United States			2,199		3,575		2,268
	Non-U.S.			1,250		9,615		2,191
Chemical								
	United States			2,755		2,220		2,215
	Non-U.S.			1,073		1,678		2,168
Corporate and financing				(1,538)		(2,103)		(2,221)
		Net income attributable to ExxonMobil (U.S. GAAP)		32,580		44,880		41,060
Earnings per common share				7.37		9.70		8.43
Earnings per common share – assuming dilution				7.37		9.70		8.42

References in this discussion to total corporate earnings mean net income attributable to ExxonMobil (U.S. GAAP) from the consolidated income statement. Unless otherwise indicated, references to earnings, Upstream, Downstream, Chemical and Corporate and Financing segment earnings, and earnings per share are ExxonMobil's share after excluding amounts attributable to noncontrolling interests.

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; rates of field decline; financing sources; the resolution of contingencies and uncertain tax positions; environmental and capital expenditures; could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; the outcome of commercial negotiations; political or regulatory events, and other factors discussed herein and in Item 1A. Risk Factors.

The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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.

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. Price ranges for crude oil, natural gas, refined products, and chemical 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 2040, the world's population is projected to grow to approximately 8.8 billion people, or close to 2 billion more than in 2010. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. As economies and populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 35 percent from 2010 to 2040. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development).

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient and lower-emission fuels, technologies and practices will continue to help significantly reduce energy consumption and emissions per unit of economic output over time. Substantial efficiency gains are likely in all key aspects of the world's economy through 2040, affecting energy requirements for transportation, power generation, industrial applications, and residential and commercial needs.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 40 percent from 2010 to 2040. The global growth in transportation demand is likely to account for approximately 70 percent of the growth in liquid fuels demand over this period. Nearly all the world's transportation fleets will continue to run on liquid fuels because they are abundant, widely available, easy to transport, and provide a large quantity of energy in small volumes.

Demand for electricity around the world is likely to increase approximately 90 percent by 2040, led by growth in developing countries. Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand is likely to grow most significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today, coal has the largest fuel share in the power sector, but its share is likely to decline significantly by 2040 as policies are gradually adopted to reduce environmental impacts including those related to local air quality and greenhouse gas emissions. Nuclear power and renewables, led by hydropower and wind, are also expected to grow significantly over the period.

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

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ease of transportation, distribution and storage to meet consumer needs. By 2040, global demand for liquid fuels is expected to grow to approximately 112 million barrels of oil equivalent per day, an increase of about 25 percent from 2010. This demand will be met by a wide variety of sources. Globally, conventional crude production will likely decline slightly through 2040. However, this decline is expected to be more than offset by rising production from a wide variety of emerging supply sources – including tight oil, deepwater, oil sands, natural gas liquids and biofuels. The world's resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availability of economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and is expected to be the fastest growing major fuel source through 2040. Global demand is expected to rise about 65 percent from 2010 to 2040, with demand likely to increase in all major regions of the world. Helping meet these needs will be significant growth in supplies of unconventional gas – the natural gas found in shale and other rock formations that was once considered uneconomic to produce. About 65 percent of the growth in natural gas supplies is expected to be from unconventional sources, which will account for about one-third of global gas supplies by 2040. Growing natural gas demand will also stimulate significant growth in the worldwide liquefied natural gas (LNG) market, which is expected to reach about 15 percent of global gas demand by 2040.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas by approximately 2025. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to less than 20 percent. Nuclear power is projected to grow significantly, albeit at a slower pace than otherwise expected in the aftermath of the Fukushima incident in Japan following the earthquake and tsunami in March 2011. Total renewable energy is likely to reach close to 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing a combined share of about 11 percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 450 percent from 2010 to 2040, reaching a combined share of about 4 percent of world energy.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide over the period 2012 2035 will be close to $19 trillion (measured in 2011 dollars) or close to $800 billion per year on average.

International accords and underlying regional and national regulations covering greenhouse gas emissions are evolving with uncertain timing and outcome, making it difficult to predict their business impact. ExxonMobil includes estimates of potential costs related to possible public policies covering energy-related greenhouse gas emissions in its long-term Outlook for Energy, which is used for assessing the business environment and in its investment evaluations.

The information provided in the Long-Term Business Outlook includes ExxonMobil's internal estimates and forecasts based upon internal data and analyses as well as publicly available information from external sources including the

International Energy Agency.

Upstream

ExxonMobil continues to maintain a diverse portfolio of exploration and development opportunities, which enables the Corporation to be selective, maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies guide our global exploration, development, production, and gas and power marketing activities. These strategies include identifying and selectively capturing the highest quality opportunities, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, maximizing the profitability of existing oil and gas production, and capitalizing on growing natural gas and power markets. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of our employees, and investment in the communities within which we operate.

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix of its production volumes between now and 2018. Oil equivalent production from North America is expected to increase over the next five years based on current capital activity plans. Currently, this growth area accounts for 32 percent of the Corporation's production. By 2018, it is expected to generate about 35 percent of total volumes. The remainder of the Corporation's production is expected to include contributions from both established operations and new projects around the globe.

In addition to an evolving geographic mix, we expect there will also be continued change in the type of opportunities from which volumes are produced. Production from diverse resource types utilizing specialized technologies such as arctic technology, deepwater drilling and production systems, heavy oil and oil sands recovery processes, unconventional gas and oil production and

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

LNG is expected to grow from about 45 percent to around 55 percent of the Corporation's output between now and 2018. We do not anticipate that the expected change in the geographic mix of production volumes, and in the types of opportunities from which volumes will be produced, will have a material impact on the nature and the extent of the risks disclosed in Item 1A. Risk Factors, or result in a material change in our level of unit operating expenses. The Corporation's overall volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the period 2014 2018. However, actual volumes will vary from year to year due to the timing of individual project start-ups and other capital activities, operational outages, reservoir performance, performance of enhanced oil recovery projects, regulatory changes, asset sales, weather events, price effects under production sharing contracts and other factors described in Item 1A. Risk Factors. Enhanced oil recovery projects extract hydrocarbons from reservoirs in excess of that which may be produced through primary recovery, i.e., through pressure depletion or natural aquifer support. They include the injection of water, gases or chemicals into a reservoir to produce hydrocarbons otherwise unobtainable.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. The Corporation has a presence in mature markets in North America and Europe, as well as in the growing Asia Pacific region. ExxonMobil's fundamental Downstream business strategies position the company to deliver long-term growth in shareholder value that is superior to competition across a range of market conditions. These strategies include maintaining best in class operations in all aspects of the business, maximizing value from leading-edge technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, leading the industry in efficiency and effectiveness, and providing quality, valued products and services to customers.

ExxonMobil has an ownership interest in 31 refineries, located in 17 countries, with distillation capacity of 5.3 million barrels per day and lubricant basestock manufacturing capacity of 126 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have significant global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes *Exxon*, *Mobil*, *Esso* and *Mobil 1*.

The downstream industry environment remains challenging. Demand weakness and overcapacity in the refining sector will continue to put pressure on margins. In the near term, we see variability in refining margins, with some regions seeing stronger margins as refineries rationalize. In North America, lower raw material and energy cost driven by increasing crude oil and natural gas production has strengthened refining margins in several areas.

Refining margins are largely driven by differences in commodity prices and 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 Intercontinental Exchange). Prices for these commodities are determined by the global marketplace and are influenced by many factors, including global and regional supply/demand balances, inventory levels, industry refinery operations, import/export balances, currency fluctuations, seasonal demand, weather and

political climate.

ExxonMobil's long term outlook is that industry refining margins will remain weak as competition remains intense and, in the near term, new capacity additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A. Risk Factors, proposed carbon policy and other climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could have negative impacts on the refining business. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

In the retail fuels marketing business, competition has caused inflation-adjusted margins to decline. In 2013, ExxonMobil completed the previously announced transition of the direct served (i.e., dealer, company-operated) retail network in the U.S. to a more capital-efficient branded distributor model and progressed this same model in portions of Europe. ExxonMobil is increasing investment in its fuels brands and developing multiple programs that will enhance the value of its consumer retail offer. The company's lubricants business continues to grow, leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains the market leader in the high value synthetic lubricants sector where competition is increasing.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. 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. In 2013, the company completed a hydrotreater project at the Singapore refinery to produce ultra low sulfur diesel, and a cogeneration project at the Augusta, Italy refinery to improve energy efficiency. Additionally, construction of a lower sulfur fuels facility at the joint Saudi Aramco and ExxonMobil SAMREF Refinery in Yanbu, Saudi Arabia is nearly complete. The company is also expanding lubricant basestock manufacturing capacity at refineries in Baytown,

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

Texas and Singapore, and expanding lube oil blending plants in China, Finland, and the U.S. to support future demand growth for finished lubricants in key markets.

Chemical

Worldwide petrochemical demand grew in 2013, led by growing demand from Asia manufacturers and consumers. North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low-cost feedstock and energy savings. Specialty product margins declined reflecting significant new industry capacity following several years of tight supplies.

ExxonMobil sustained its competitive advantage through continued operational excellence, investment and cost discipline, a balanced portfolio of products, integration with refining and upstream operations, all underpinned by proprietary technology.

In 2013 ExxonMobil started up the Singapore Chemical Expansion Project, more than doubling steam cracking capacity at the site and significantly increasing premium and specialty products capacity. Singapore is now ExxonMobil's largest integrated petrochemical complex.

REVIEW OF 2013 AND 2012 RESULTS						
		2013		**2012**		**2011**
		(millions of dollars)				
Earnings (U.S. GAAP)		32,580		44,880		41,060

2013

Earnings in 2013 of $32,580 million decreased $12,300 million from 2012.

2012

Earnings in 2012 of $44,880 million increased $3,820 million from 2011.

Upstream						

				2013		2012		2011
				(millions of dollars)				
Upstream								
	United States			4,191		3,925		5,096
	Non-U.S.			22,650		25,970		29,343
		Total		26,841		29,895		34,439

2013

Upstream earnings were $26,841 million, down $3,054 million from 2012. Higher gas realizations, partially offset by lower liquids realizations, increased earnings by $390 million. Production volume and mix effects decreased earnings by $910 million. All other items, including lower net gains from asset sales, mainly in Angola, and higher expenses, reduced earnings by $2.5 billion. On an oil equivalent basis, production was down 1.5 percent compared to 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was essentially flat. Liquids production of 2,202 kbd (thousands of barrels per day) increased 17 kbd compared with 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was up 1.6 percent, as project ramp up and lower downtime were partially offset by field decline. Natural gas production of 11,836 mcfd (millions of cubic feet per day) decreased 486 mcfd from 2012. Excluding the impacts of entitlement volumes and divestments, natural gas production was down 1.5 percent, as field decline was partially offset by higher demand, lower downtime, and project ramp up. Earnings from U.S. Upstream operations for 2013 were $4,191 million, up $266 million from 2012. Earnings outside the U.S. were $22,650 million, down $3,320 million from the prior year.

2012

Upstream earnings were $29,895 million, down $4,544 million from 2011. Lower liquids realizations, partly offset by improved natural gas realizations, decreased earnings by about $100 million. Production volume and mix effects decreased earnings by $2.3 billion. All other items, including higher operating expenses, unfavorable tax items, lower gains on asset sales, and unfavorable foreign exchange effects, reduced earnings by $2.1 billion. On an oil equivalent basis, production was down 5.9 percent compared to 2011. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was down 1.7 percent. Liquids production of 2,185 kbd decreased 127 kbd from 2011. Excluding the impacts of entitlement

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

volumes, OPEC quota effects and divestments, liquids production was down 1.6 percent, as field decline was partly offset by project ramp up in West Africa and lower downtime. Natural gas production of 12,322 mcfd decreased 840 mcfd from 2011. Excluding the impacts of entitlement volumes and divestments, natural gas production was down 1.9 percent, as field decline was partially offset by higher demand and lower downtime. Earnings from U.S. Upstream operations for 2012 were $3,925 million, down $1,171 million from 2011. Earnings outside the U.S. were $25,970 million, down $3,373 million.

Upstream additional information									
					2013		**2012**		**2011**
					(thousands of barrels daily)				
Volumes Reconciliation (Oil-equivalent production)*(1)*									
Prior year					4,239		4,506		4,447
	Entitlements - Net Interest				(38)		(129)		(20)
	Entitlements - Price / Spend				(9)		(10)		(104)
	Quotas				3		9		32
	Divestments				(26)		(61)		(43)
	Net growth				6		(76)		194
Current Year					4,175		4,239		4,506
(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.									

Listed below are descriptions of ExxonMobil's entitlement volume effects. These descriptions are provided to facilitate understanding of the terms.

Production Sharing Contract (PSC) Net Interest Reductions are contractual reductions in ExxonMobil's share of production volumes covered by PSCs. These reductions typically occur when cumulative investment returns or production volumes achieve thresholds as specified in the PSCs. Once a net interest reduction has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Price and Spend Impacts on Volumes are fluctuations in ExxonMobil's share of production volumes caused by changes in oil and gas prices or spending levels from one period to another. For example, at higher prices, fewer barrels are required for ExxonMobil to recover its costs. According to the terms of contractual arrangements or government royalty regimes, price or spending variability can increase or decrease royalty burdens and/or volumes attributable to ExxonMobil. These effects generally vary from period to period with field spending patterns or market prices for

crude oil or natural gas.

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

Downstream								
				2013		**2012**		**2011**
				(millions of dollars)				
Downstream								
	United States			2,199		3,575		2,268
	Non-U.S.			1,250		9,615		2,191
		Total		3,449		13,190		4,459

2013

Downstream earnings of $3,449 million decreased $9,741 million from 2012 driven by the absence of the $5.3 billion gain associated with the Japan restructuring. Lower margins, mainly refining, decreased earnings by $2.9 billion. Volume and mix effects decreased earnings by $310 million. All other items, including higher operating expenses, unfavorable foreign exchange impacts, and lower divestments, decreased earnings by $1.2 billion. Petroleum product sales of 5,887 kbd decreased 287 kbd from 2012. U.S. Downstream earnings were $2,199 million, down $1,376 million from 2012. Non-U.S. Downstream earnings were $1,250 million, a decrease of $8,365 million from the prior year.

2012

Downstream earnings of $13,190 million increased $8,731 million from 2011. Stronger refining-driven margins increased earnings by $2.6 billion, while volume and mix effects increased earnings by about $200 million. All other items increased earnings by $5.9 billion due primarily to the $5.3 billion gain associated with the Japan restructuring and other divestment gains. Petroleum product sales of 6,174 kbd decreased 239 kbd from 2011 due mainly to the Japan restructuring and divestments. U.S. Downstream earnings were $3,575 million, up $1,307 million from 2011. Non-U.S. Downstream earnings were $9,615 million, an increase of $7,424 million from 2011.

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Chemical								
				2013		**2012**		**2011**
				(millions of dollars)				
Chemical								
	United States			2,755		2,220		2,215
	Non-U.S.			1,073		1,678		2,168
		Total		3,828		3,898		4,383

2013

Chemical earnings of $3,828 million were $70 million lower than 2012. The absence of the gain associated with the Japan restructuring decreased earnings by $630 million. Higher margins increased earnings by $480 million, while volume and mix effects increased earnings by $80 million. Prime product sales of 24,063 kt (thousands of metric tons) were down 94 kt from 2012. U.S. Chemical earnings were $2,755 million, up $535 million from 2012. Non-U.S. Chemical earnings were $1,073 million, $605 million lower than the prior year.

2012

Chemical earnings of $3,898 million were $485 million lower than 2011. Margins decreased earnings by $440 million, while volume effects lowered earnings by $100 million. All other items increased earnings by $50 million, as a $630 million gain associated with the Japan restructuring and favorable tax impacts were mostly offset by unfavorable foreign exchange effects and higher operating expenses. Prime product sales of 24,157 kt were down 849 kt from 2011. U.S. Chemical earnings were $2,220 million, up $5 million from 2011. Non-U.S. Chemical earnings were $1,678 million, $490 million lower than 2011.

Corporate and Financing						
		2013		**2012**		**2011**
		(millions of dollars)				
Corporate and financing		(1,538)		(2,103)		(2,221)

2013

Corporate and financing expenses were $1,538 million, down $565 million from 2012, as favorable tax impacts were partially offset by the absence of the Japan restructuring gain.

2012

Corporate and financing expenses were $2,103 million, down $118 million from 2011.

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

LIQUIDITY AND CAPITAL RESOURCES							
Sources and Uses of Cash							
			2013		**2012**		**2011**
			(millions of dollars)				
Net cash provided by/(used in)							
	Operating activities		44,914		56,170		55,345
	Investing activities		(34,201)		(25,601)		(22,165)
	Financing activities		(15,476)		(33,868)		(28,256)
Effect of exchange rate changes			(175)		217		(85)
Increase/(decrease) in cash and cash equivalents			(4,938)		(3,082)		4,839
			(December 31)				
Cash and cash equivalents			4,644		9,582		12,664
Cash and cash equivalents - restricted			269		341		404
Total cash and cash equivalents			4,913		9,923		13,068

Total cash and cash equivalents were $4.9 billion at the end of 2013, $5.0 billion lower than the prior year. The major sources of funds in 2013 were net income including noncontrolling interests of $33.4 billion, the adjustment for the noncash provision of $17.2 billion for depreciation and depletion, and a net debt increase of $11.6 billion. The major uses of funds included spending for additions to property, plant and equipment of $33.7 billion, the purchase of shares of ExxonMobil stock of $16.0 billion, dividends to shareholders of $10.9 billion and a change in working capital, excluding cash and debt, of $4.7 billion. Included in total cash and cash equivalents at year-end 2013 was $0.3 billion of restricted cash.

Total cash and cash equivalents were $9.9 billion at the end of 2012, $3.1 billion lower than the prior year. Higher earnings and a higher adjustment for noncash transactions were more than offset by lower proceeds from sales of subsidiaries and property, plant and equipment, a net debt decrease compared to a prior year debt increase, and a higher adjustment for net gains on asset sales. Included in total cash and cash equivalents at year-end 2012 was $0.3 billion of restricted cash. For additional details, see the Consolidated Statement of Cash Flows.

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, and may be supplemented by long-term and short-term debt, including a revolving commercial paper program. The Corporation has committed lines of credit of $6.5 billion which were unused as of December 31, 2013. Cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns.

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 an average of approximately 3 percent per year over the next few years. 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, work activity, 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 in quality opportunities and project execution. Over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. 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. Please refer to Item 1A. Risk Factors for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2013 were $42.5 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an average investment profile of about $37 billion per year for the next several years. Actual spending could vary depending on the progress of individual projects and property acquisitions. 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

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

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.

Cash Flow from Operating Activities

2013

Cash provided by operating activities totaled $44.9 billion in 2013, $11.3 billion lower than 2012. The major source of funds was net income including noncontrolling interests of $33.4 billion, a decrease of $14.2 billion. The noncash provision of $17.2 billion for depreciation and depletion was higher than 2012. The adjustment for net gains on asset sales was $1.8 billion compared to an adjustment of $13.0 billion in 2012. Changes in operational working capital, excluding cash and debt, decreased cash in 2013 by $4.7 billion.

2012

Cash provided by operating activities totaled $56.2 billion in 2012, $0.8 billion higher than 2011. The major source of funds was net income including noncontrolling interests of $47.7 billion, an increase of $5.5 billion. The noncash provision of $15.9 billion for depreciation and depletion was slightly higher than 2011. The adjustments for other noncash transactions and changes in operational working capital, excluding cash and debt, both increased cash in 2012, while the adjustment for net gains on asset sales decreased cash by $13.0 billion in 2012.

Cash Flow from Investing Activities

2013

Cash used in investment activities netted to $34.2 billion in 2013, $8.6 billion higher than 2012. Spending for property, plant and equipment of $33.7 billion decreased $0.6 billion from 2012. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $2.7 billion compared to $7.7 billion in 2012. Additional investments and advances were $3.8 billion higher in 2013.

2012

Cash used in investment activities netted to $25.6 billion in 2012, $3.4 billion higher than 2011. Spending for property, plant and equipment of $34.3 billion increased $3.3 billion from 2011. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $7.7 billion compared to $11.1 billion in 2011. The decrease reflects that a $3.6 billion deposit was received in 2011 for a sale that closed in 2012. Additional investments and advances were $3.0 billion lower in 2012.

Cash Flow from Financing Activities

2013

Cash used in financing activities was $15.5 billion in 2013, $18.4 billion lower than 2012. Dividend payments on common shares increased to $2.46 per share from $2.18 per share and totaled $10.9 billion, a pay-out of 33 percent of net income. Total debt increased $11.1 billion to $22.7 billion at year-end.

ExxonMobil share of equity increased $8.1 billion to $174.0 billion. The addition to equity for earnings of $32.6 billion was partially offset by reductions for distributions to ExxonMobil shareholders of $10.9 billion of dividends and $15.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2013, Exxon Mobil Corporation purchased 177 million shares of its common stock for the treasury at a gross cost of $16.0 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 3.7 percent from 4,502 million to 4,335 million at the end of 2013. 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.

2012

Cash used in financing activities was $33.9 billion in 2012, $5.6 billion higher than 2011. Dividend payments on common shares increased to $2.18 per share from $1.85 per share and totaled $10.1 billion, a pay-out of 22 percent of net income. Total debt decreased $5.5 billion to $11.6 billion at year-end.

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ExxonMobil share of equity increased $11.5 billion to $165.9 billion. The addition to equity for earnings of $44.9 billion was partially offset by reductions for distributions to ExxonMobil shareholders of $10.1 billion of dividends and $20.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2012, Exxon Mobil Corporation purchased 244 million shares of its common stock for the treasury at a gross cost of $21.1 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 4.9 percent from 4,734 million to 4,502 million at the end of 2012. Purchases were made in both the open market and through negotiated transactions.

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

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2013. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period								
		Note						**2019**		
		Reference				**2015-**		**and**		
Commitments		**Number**		**2014**		**2018**		**Beyond**		**Total**
		(millions of dollars)								
Long-term debt *(1)*		14		-		3,052		3,839		6,891
	– Due in one year *(2)*	6		1,034		-		-		1,034
Asset retirement obligations *(3)*		9		799		3,026		9,163		12,988
Pension and other postretirement obligations *(4)*		17		2,983		4,379		14,074		21,436
Operating leases *(5)*		11		2,391		3,530		1,517		7,438
Unconditional purchase obligations *(6)*		16		144		629		463		1,236
Take-or-pay obligations *(7)*				3,060		10,893		15,657		29,610
Firm capital commitments *(8)*				19,258		9,616		885		29,759

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 unrecognized tax benefits totaling $7.8 billion as of December 31, 2013, 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 19, Income, Sales-Based and Other Taxes.

Notes:

(1) Includes capitalized lease obligations of $375 million.

(2) The amount due in one year is included in notes and loans payable of $15,808 million.

(3) The fair value of asset retirement obligations, primarily upstream 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 2014 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 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. The undiscounted obligations of $1,236 million mainly pertain to pipeline throughput agreements and include $457 million of obligations to equity companies.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $29,610 million mainly pertain to pipeline, manufacturing supply and terminaling agreements.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $29.8 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $16.3 billion was associated with projects in Canada, Australia, Africa, United Arab Emirates and Malaysia. The Corporation expects to fund the majority of these projects with internally generated funds that may be supplemented by long-term and short-term debt, including a revolving commercial paper program.

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

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2013, for guarantees relating to notes, loans and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. These 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.

Financial Strength

On December 31, 2013, the Corporation's unused short-term committed lines of credit totaled approximately $5.9 billion (Note 6) and unused long-term committed lines of credit totaled approximately $0.6 billion (Note 14).

The table below shows the Corporation's fixed-charge coverage and consolidated debt-to-capital ratios. The data demonstrate the Corporation's creditworthiness.

		2013		2012		2011
Fixed-charge coverage ratio (times)		55.7		62.4		53.4
Debt to capital (percent)		11.2		6.3		9.6
Net debt to capital (percent)		9.1		1.2		2.6

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.

Litigation and Other Contingencies

As discussed in Note 16, a variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. 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 material adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole.

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. Refer to Note 16 for additional information on legal proceedings and other contingencies.

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

CAPITAL AND EXPLORATION EXPENDITURES											
		2013				**2012**					
		U.S.	**Non-U.S.**		**Total**	**U.S.**	**Non-U.S.**		**Total**		
		(millions of dollars)									
Upstream *(1)*		9,145	29,086		38,231	11,080	25,004		36,084		
Downstream		951	1,462		2,413	634	1,628		2,262		
Chemical		963	869		1,832	408	1,010		1,418		
Other		13	-		13	35	-		35		
	Total	11,072	31,417		42,489	12,157	27,642		39,799		
(1) Exploration expenses included.											

Capital and exploration expenditures in 2013 were $42.5 billion, including $4.3 billion for acquisitions, as the Corporation continued to pursue opportunities to find and produce new supplies of oil and natural gas to meet global demand for energy. The Corporation anticipates an average investment profile of about $37 billion per year for the next several years. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $38.2 billion in 2013 was up 6 percent from 2012. Property acquisition costs in the Upstream in 2013 of $4.2 billion were $1.2 billion higher than in 2012. Investments in 2013 included projects in the U.S. Gulf of Mexico and Alaska, exploration in Russia and continued progress on world-class projects in Canada, Australia and Papua New Guinea. The majority of 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 was 66 percent of total proved reserves at year-end 2013, and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved from undeveloped to developed status.

Capital investments in the Downstream totaled $2.4 billion in 2013, an increase of $0.2 billion from 2012, mainly reflecting higher refining margin improvement project spending. The Chemical capital expenditures of $1.8 billion increased $0.4 billion from 2012 with higher investments in the U.S., Saudi Arabia and China more than offsetting reduced spending on the completed Singapore Chemical Plant expansion.

TAXES							
			2013		**2012**		**2011**
			(millions of dollars)				

Income taxes			24,263		31,045		31,051
	Effective income tax rate		*48%*		*44%*		*46%*
Sales-based taxes			30,589		32,409		33,503
All other taxes and duties			36,396		38,857		43,544
	Total		91,248		102,311		108,098

2013

Income, sales-based and all other taxes and duties totaled $91.2 billion in 2013, a decrease of $11.1 billion or 11 percent from 2012. Income tax expense, both current and deferred, was $24.3 billion, $6.8 billion lower than 2012, with the impact of lower earnings partially offset by the higher effective tax rate. The effective tax rate was 48 percent compared to 44 percent in the prior year due to the absence of favorable tax impacts on divestments. Sales-based and all other taxes and duties of $67.0 billion in 2013 decreased $4.3 billion reflecting the 2012 Japan restructuring.

2012

Income, sales-based and all other taxes and duties totaled $102.3 billion in 2012, a decrease of $5.8 billion or 5 percent from 2011. Income tax expense, both current and deferred, was $31.0 billion, flat with 2011, with the impact of higher earnings offset by the lower effective tax rate. The effective tax rate was 44 percent compared to 46 percent in the prior year due to a lower effective tax rate on divestments. Sales-based and all other taxes and duties of $71.3 billion in 2012 decreased $5.8 billion reflecting the Japan restructuring.

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

ENVIRONMENTAL MATTERS

Environmental Expenditures					
			2013		**2012**
			(millions of dollars)		
Capital expenditures			2,474		1,989
Other expenditures			3,538		3,523
	Total		6,012		5,512

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 monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2013 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $6.0 billion. The total cost for such activities is expected to remain in this range in 2014 and 2015 (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 2013 for environmental liabilities were $321 million ($391 million in 2012) and the balance sheet reflects accumulated liabilities of $773 million as of December 31, 2013, and $841 million as of December 31, 2012.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*		**2013**		**2012**		**2011**
Crude oil and NGL ($/barrel)		97.48		100.29		100.79
Natural gas ($/kcf)		4.60		3.90		4.65
(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, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $350 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 $175 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 broad indicators 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.

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

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 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 35 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 investments 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.

The Corporation has an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing to the Corporation's strategic objectives. The result is an efficient capital base, and the Corporation has seldom had 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. With respect to derivatives activities, the Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivatives described in Note 13. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries 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 has access to significant

capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, and may be supplemented by long-term and short-term debt, including a revolving commercial paper program. Some joint-venture partners are dependent on the credit markets, and their funding ability may impact the development pace of joint-venture projects.

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 to mitigate the impact of changes in currency values, and exposures related to the Corporation's limited use of the currency exchange contracts are not material.

Inflation and Other Uncertainties

The general rate of inflation in many major countries of operation has remained moderate over the past few years, and the associated impact on non-energy costs has generally been mitigated by cost reductions from efficiency and productivity improvements. Increased demand for certain services and materials has resulted in higher operating and capital costs in recent years. The Corporation works to counter upward pressure on costs through its economies of scale in global procurement and its efficient project management practices.

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

CRITICAL ACCOUNTING ESTIMATES

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 Corporation's accounting policies are summarized in Note 1.

Oil and Gas Reserves

Evaluations of oil and gas reserves are important to the effective management of upstream assets. They are an integral part of investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis to calculate unit-of-production depreciation rates and to evaluate impairment.

Oil and gas reserves include both proved and unproved reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible. 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 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 the Reserves Technical Oversight group which has 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 reserve estimation process are covered in Disclosure of Reserves in Item 2.

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 was 66 percent of total proved reserves at year-end 2013 (including both consolidated and equity company reserves), and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved from undeveloped to developed status.

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 prices and year-end costs that are used in the estimation of reserves. Revisions can also result from significant changes in development strategy or production equipment/facility capacity.

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. 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. An asset group would be impaired if its undiscounted cash flows were less than the asset’s carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value.

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. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

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

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses 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. Potential trigger events for impairment evaluation include a significant decrease in current and projected reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected, and current period operating losses combined with a history and forecast of operating or cash flow losses.

In general, the Corporation does not view temporarily low prices or margins 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 field production profiles, which are updated annually. Cash flow estimates for impairment testing exclude the effects 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. Future prices used for any impairment tests will vary from the ones used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain 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. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations are disclosed in Note 9 to the financial statements.

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and 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. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in Note 10 to the financial statements.

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, liabilities, revenues and expenses. Amounts representing the Corporation's interest in the underlying net assets of other significant entities that it does not control, but over which it exercises significant influence, are accounted for using the equity method of accounting.

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 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 share of all assets and liabilities in these partially owned companies rather than only its interest in net equity. This method of accounting for investments in partially-owned companies is not permitted by U.S. 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 U.S. GAAP standards, the Corporation includes its share of debt of these partially-owned companies in the determination of average capital employed.

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

Pension Benefits

The Corporation and its affiliates sponsor over 100 defined benefit (pension) plans in about 50 countries. Pension and Other Postretirement Benefits (Note 17) 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 those in the U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in compliance with the requirements of governmental authorities and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, these standards often require approaches and assumptions 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 as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2013 was 7.25 percent. The 10 year and 20 year actual returns on U.S. pension plan assets were 7 percent and 9 percent, respectively. 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 percentages 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 $150 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 16.

The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable, and 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. For purposes of our litigation contingency disclosures, “significant” includes material matters as well as other items which management believes should be disclosed.

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 material 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.

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained

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

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 or expected to be 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 19.

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.

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 criteria established in *Internal Control – Integrated Framework (1992)* 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, 2013.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2013, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson	Andrew P. Swiger	Patrick T. Mulva
Chief Executive Officer	Senior Vice President	Vice President and Controller
	(Principal Financial Officer)	(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Exxon Mobil Corporation:

In our opinion, the accompanying Consolidated Balance Sheets and the related Consolidated Statements of Income, Comprehensive Income, Changes in Equity and Cash Flows present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2013, and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* 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 the accompanying 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.

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.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas

February 26, 2014

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2013	2012	2011
		(millions of dollars)		
Revenues and other income				
Sales and other operating revenue *(1)*		420,836	451,509	467,029
Income from equity affiliates	7	13,927	15,010	15,289
Other income		3,492	14,162	4,111
Total revenues and other income		438,255	480,681	486,429
Costs and other deductions				
Crude oil and product purchases		244,156	263,535	266,534
Production and manufacturing expenses		40,525	38,521	40,268
Selling, general and administrative expenses		12,877	13,877	14,983
Depreciation and depletion		17,182	15,888	15,583
Exploration expenses, including dry holes		1,976	1,840	2,081
Interest expense		9	327	247
Sales-based taxes *(1)*	19	30,589	32,409	33,503
Other taxes and duties	19	33,230	35,558	39,973
Total costs and other deductions		380,544	401,955	413,172
Income before income taxes		57,711	78,726	73,257
Income taxes	19	24,263	31,045	31,051
Net income including noncontrolling interests		33,448	47,681	42,206
Net income attributable to noncontrolling interests		868	2,801	1,146
Net income attributable to ExxonMobil		32,580	44,880	41,060
Earnings per common share *(dollars)*	12	7.37	9.70	8.43
Earnings per common share - assuming dilution *(dollars)*	12	7.37	9.70	8.42

(1) Sales and other operating revenue includes sales-based taxes of $30,589 million for 2013, $32,409 million for 2012 and $33,503 million for 2011.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2013	2012	2011
	(millions of dollars)		
Net income including noncontrolling interests	33,448	47,681	42,206
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(3,620)	920	(867)
Adjustment for foreign exchange translation (gain)/loss included in net income	(23)	(4,352)	-
Postretirement benefits reserves adjustment (excluding amortization)	3,174	(3,574)	(4,907)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,820	2,395	1,217
Change in fair value of cash flow hedges	-	-	28
Realized (gain)/loss from settled cash flow hedges included in net income	-	-	(83)
Total other comprehensive income	1,351	(4,611)	(4,612)
Comprehensive income including noncontrolling interests	34,799	43,070	37,594
Comprehensive income attributable to noncontrolling interests	760	1,251	834
Comprehensive income attributable to ExxonMobil	34,039	41,819	36,760

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2013	Dec. 31 2012
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		4,644	9,582
Cash and cash equivalents - restricted		269	341
Notes and accounts receivable, less estimated doubtful amounts	6	33,152	34,987
Inventories			
Crude oil, products and merchandise	3	12,117	10,836
Materials and supplies		4,018	3,706
Other current assets		5,108	5,008
Total current assets		59,308	64,460
Investments, advances and long-term receivables	8	36,328	34,718
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	243,650	226,949
Other assets, including intangibles, net		7,522	7,668
Total assets		346,808	333,795
Liabilities			
Current liabilities			
Notes and loans payable	6	15,808	3,653
Accounts payable and accrued liabilities	6	48,085	50,728
Income taxes payable		7,831	9,758
Total current liabilities		71,724	64,139
Long-term debt	14	6,891	7,928
Postretirement benefits reserves	17	20,646	25,267
Deferred income tax liabilities	19	40,530	37,570
Long-term obligations to equity companies		4,742	3,555
Other long-term obligations		21,780	23,676
Total liabilities		166,313	162,135
Commitments and contingencies	16		
Equity			
Common stock without par value			
(9,000 million shares authorized, 8,019 million shares issued)		10,077	9,653

	Earnings reinvested					387,432		365,727
	Accumulated other comprehensive income					(10,725)		(12,184)
	Common stock held in treasury							
		(3,684 million shares in 2013 and 3,517 million shares in 2012)				(212,781)		(197,333)
			ExxonMobil share of equity			174,003		165,863
	Noncontrolling interests					6,492		5,797
			Total equity			180,495		171,660
			Total liabilities and equity			346,808		333,795

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2013	2012	2011
		(millions of dollars)		
Cash flows from operating activities				
Net income including noncontrolling interests		33,448	47,681	42,206
Adjustments for noncash transactions				
Depreciation and depletion		17,182	15,888	15,583
Deferred income tax charges/(credits)		754	3,142	142
Postretirement benefits expense				
in excess of/(less than) net payments		2,291	(315)	544
Other long-term obligation provisions				
in excess of/(less than) payments		(2,566)	1,643	(151)
Dividends received greater than/(less than) equity in current				
earnings of equity companies		3	(1,157)	(273)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(305)	(1,082)	(7,906)
- Inventories		(1,812)	(1,873)	(2,208)
- Other current assets		(105)	(42)	222
Increase/(reduction) - Accounts and other payables		(2,498)	3,624	8,880
Net (gain) on asset sales	5	(1,828)	(13,018)	(2,842)
All other items - net		350	1,679	1,148
Net cash provided by operating activities		44,914	56,170	55,345
Cash flows from investing activities				
Additions to property, plant and equipment		(33,669)	(34,271)	(30,975)
Proceeds associated with sales of subsidiaries, property, plant				
and equipment, and sales and returns of investments	5	2,707	7,655	11,133
Decrease/(increase) in restricted cash and cash equivalents		72	63	224
Additional investments and advances		(4,435)	(598)	(3,586)
Collection of advances		1,124	1,550	1,119
Additions to marketable securities		-	-	(1,754)
Sales of marketable securities		-	-	1,674
Net cash used in investing activities		(34,201)	(25,601)	(22,165)

Cash flows from financing activities										
	Additions to long-term debt			345		995		702		
	Reductions in long-term debt			(13)		(147)		(266)		
	Additions to short-term debt			16		958		1,063		
	Reductions in short-term debt			(756)		(4,488)		(1,103)		
	Additions/(reductions) in debt with three months or less maturity			12,012		(226)		1,561		
	Cash dividends to ExxonMobil shareholders			(10,875)		(10,092)		(9,020)		
	Cash dividends to noncontrolling interests			(304)		(327)		(306)		
	Changes in noncontrolling interests			(1)		204		(16)		
	Tax benefits related to stock-based awards			48		130		260		
	Common stock acquired			(15,998)		(21,068)		(22,055)		
	Common stock sold			50		193		924		
		Net cash used in financing activities		(15,476)		(33,868)		(28,256)		
Effects of exchange rate changes on cash				(175)		217		(85)		
Increase/(decrease) in cash and cash equivalents				(4,938)		(3,082)		4,839		
Cash and cash equivalents at beginning of year				9,582		12,664		7,825		
Cash and cash equivalents at end of year				4,644		9,582		12,664		

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity					
		Accumulated	Common			
		Other	Stock	ExxonMobil	Non-	
	Common	Earnings	Comprehensive	Held in	Share of	controlling	Total
	Stock	Reinvested	Income	Treasury	Equity	Interests	Equity
	(millions of dollars)						
Balance as of December 31, 2010	9,371	298,899	(4,823)	(156,608)	146,839	5,840	152,679
Amortization of stock-based awards	742	-	-	-	742	-	742
Tax benefits related to stock-based awards	202	-	-	-	202	-	202
Other	(803)	-	-	-	(803)	(5)	(808)
Net income for the year	-	41,060	-	-	41,060	1,146	42,206
Dividends - common shares	-	(9,020)	-	-	(9,020)	(306)	(9,326)
Other comprehensive income	-	-	(4,300)	-	(4,300)	(312)	(4,612)
Acquisitions, at cost	-	-	-	(22,055)	(22,055)	(15)	(22,070)
Dispositions	-	-	-	1,731	1,731	-	1,731
Balance as of December 31, 2011	9,512	330,939	(9,123)	(176,932)	154,396	6,348	160,744
Amortization of stock-based awards	806	-	-	-	806	-	806
Tax benefits related to stock-based awards	178	-	-	-	178	-	178
Other	(843)	-	-	-	(843)	(1,441)	(2,284)
Net income for the year	-	44,880	-	-	44,880	2,801	47,681
Dividends - common shares	-	(10,092)	-	-	(10,092)	(327)	(10,419)
Other comprehensive income	-	-	(3,061)	-	(3,061)	(1,550)	(4,611)
Acquisitions, at cost	-	-	-	(21,068)	(21,068)	(34)	(21,102)

	Dispositions		-		-		-		667		667		-		667
Balance as of December 31, 2012			9,653		365,727		(12,184)		(197,333)		165,863		5,797		171,660
	Amortization of stock-based awards		761		-		-		-		761		-		761
	Tax benefits related to stock-based awards		162		-		-		-		162		-		162
	Other		(499)		-		-		-		(499)		240		(259)
	Net income for the year		-		32,580		-		-		32,580		868		33,448
	Dividends - common shares		-		(10,875)		-		-		(10,875)		(304)		(11,179)
	Other comprehensive income		-		-		1,459		-		1,459		(108)		1,351
	Acquisitions, at cost		-		-		-		(15,998)		(15,998)		(1)		(15,999)
	Dispositions		-		-		-		550		550		-		550
Balance as of December 31, 2013			10,077		387,432		(10,725)		(212,781)		174,003		6,492		180,495

					Held in		
Common Stock Share Activity			**Issued**		**Treasury**		**Outstanding**
			(millions of shares)				
Balance as of December 31, 2010			8,019		(3,040)		4,979
	Acquisitions		-		(278)		(278)
	Dispositions		-		33		33
Balance as of December 31, 2011			8,019		(3,285)		4,734
	Acquisitions		-		(244)		(244)
	Dispositions		-		12		12
Balance as of December 31, 2012			8,019		(3,517)		4,502
	Acquisitions		-		(177)		(177)
	Dispositions		-		10		10
Balance as of December 31, 2013			8,019		(3,684)		4,335

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 2013 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation. The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses.

Amounts representing the Corporation's interest in entities that it does not control, but over which it 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."

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

The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in Accumulated Other Comprehensive Income.

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. 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.

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combined and recorded as exchanges measured at the book value of the item sold.

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).

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 forecasted 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 item.

Fair Value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

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. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates 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.

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 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 and are expensed as incurred. 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.

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, refining and chemical margins and foreign currency exchange rates. Annual volumes are based on 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. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value.

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. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allowances are reviewed at least annually.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any 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.

Asset Retirement Obligations and Environmental Liabilities. The Corporation incurs retirement obligations for certain 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. 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 and Africa, 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.

Stock-Based Payments. The Corporation awards stock-based compensation to employees in the form of restricted stock and restricted stock units. Compensation expense is measured by the price of the stock at the date of grant and is recognized in income over the requisite service period. See Note 15, Incentive Program, for further details.

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2013 that had a material impact on the Corporation’s financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,044 million in 2013, $1,042 million in 2012 and $1,044 million in 2011.

Net income included before-tax aggregate foreign exchange transaction gains of $155 million and $159 million, and losses of $184 million in 2013, 2012 and 2011, respectively.

In 2013, 2012 and 2011, net income included gains of $282 million, $328 million and $292 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $21.2 billion and $21.3 billion at December 31, 2013, and 2012, respectively.

Crude oil, products and merchandise as of year-end 2013 and 2012 consist of the following:

			2013		2012