EXXON MOBIL CORP
Form 10-K
February 24, 2016

2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015

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 (4,152,756,609 shares outstanding at January 31, 2016)	**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 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

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

Indicate by check mark 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 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 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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $83.20 on the New York Stock Exchange composite tape, was in excess of $346 billion.

Documents Incorporated by Reference: Proxy Statement for the 2016 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2015

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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. 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 2015 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $5.6 billion, of which $3.8 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to decrease to approximately $5 billion in 2016 and 2017, mainly reflecting lower project activity in Canada. Capital expenditures are expected to account for approximately 30 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 2015. For technology licensed to third parties, revenues totaled approximately $158 million in 2015. 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 73.5 thousand, 75.3 thousand, and 75.0 thousand at years ended 2015, 2014 and 2013, 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 2.1 thousand, 8.4 thousand, and 9.8 thousand at years ended 2015, 2014 and 2013, respectively. The decrease in CORS employees reflects the multi year transition of the company operated retail network in portions of Europe to a more capital efficient Branded Wholesaler model.

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. Any material decline in oil or natural gas prices could have a material adverse effect on certain of the Company's operations, especially in the Upstream segment, financial condition and proved reserves. On the other hand, a material increase in oil or natural gas prices could have a material adverse effect on certain of the Company's operations, especially in the Downstream and Chemical segments.

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 or electric 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. ExxonMobil is subject to laws and sanctions imposed by the U.S. or by other jurisdictions where we do business that may prohibit ExxonMobil or certain of its affiliates from doing business in certain countries, or restricting the kind of business that may be conducted. Such restrictions may provide a competitive advantage to competitors who may not be subject to 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 as scheduled 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, including developing technologies to help reduce greenhouse gas emissions.

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 facilities are designed, constructed, and operated to withstand a variety of extreme climatic and other conditions, with safety factors built in to cover a number of engineering uncertainties, including those associated with wave, wind, and current intensity, marine ice flow patterns, permafrost stability, storm surge magnitude, temperature extremes, extreme rain fall events, and earthquakes. Our consideration of changing weather conditions and inclusion of safety factors in design covers the engineering uncertainties that climate change and other events may potentially introduce. Our ability to mitigate the adverse impacts of these events depends in part upon the effectiveness of our robust facility engineering as well as our rigorous disaster preparedness and response and 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 2015

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. 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. When crude oil and natural gas prices are in the range seen in early 2016 for an extended period of time, under the Securities and Exchange Commission's (SEC) definition of proved reserves, certain quantities of oil and natural gas could temporarily not qualify as proved reserves. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to ExxonMobil. Otherwise, no major discovery or other favorable or adverse event has occurred since December 31, 2015, 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	1,155	272	-	-	13,353	3,652
Canada/South America *(1)*	92	9	4,108	581	552	4,882
Europe	158	34	-	-	1,593	458
Africa	738	162	-	-	750	1,025
Asia	1,586	121	-	-	4,917	2,526
Australia/Oceania	73	34	-	-	1,962	434
Total Consolidated	3,802	632	4,108	581	23,127	12,977
Equity Companies						
United States	221	7	-	-	156	254
Europe	25	-	-	-	6,146	1,049
Asia	802	349	-	-	15,233	3,690
Total Equity Company	1,048	356	-	-	21,535	4,993
Total Developed	4,850	988	4,108	581	44,662	17,970
Undeveloped						
Consolidated Subsidiaries						

United States	1,223	396	-	-	6,027	2,624
Canada/South America *(1)*	168	6	452	-	575	722
Europe	26	8	-	-	363	95
Africa	225	5	-	-	43	237
Asia	1,239	-	-	-	412	1,308
Australia/Oceania	52	31	-	-	5,079	929
Total Consolidated	2,933	446	452	-	12,499	5,915
Equity Companies						
United States	33	6	-	-	64	50
Europe	-	-	-	-	1,757	293
Asia	275	52	-	-	1,228	531
Total Equity Company	308	58	-	-	3,049	874
Total Undeveloped	3,241	504	452	-	15,548	6,789
Total Proved Reserves	8,091	1,492	4,560	581	60,210	24,759

(1) South America includes proved developed reserves of 0.1 million barrels of crude oil and natural gas liquids and 23 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 anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; changes in the amount and timing of capital investments that may vary depending on the oil and gas price environment; and other factors described in Item 1A. Risk Factors.

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 natural gas price levels. In addition, proved reserves could be affected by an extended period of low prices which could reduce the level of the Corporation’s capital spending and also impact our partners’ capacity to fund their share of joint projects.

When crude oil and natural gas prices are in the range seen in late 2015 and early 2016 for an extended period of time, under the SEC definition of proved reserves, certain quantities of oil and natural gas, such as oil sands operations in Canada and natural gas operations in North America could temporarily not qualify as proved reserves. Amounts that could be required to be de-booked as proved reserves on an SEC basis are subject to being re-booked as proved reserves at some point in the future when price levels recover, costs decline, or operating efficiencies occur. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to ExxonMobil. We do not expect any temporary changes in reported proved reserves under SEC definitions to affect the operation of the underlying projects or to alter our outlook for future production volumes.

B. Technologies Used in Establishing Proved Reserves Additions in 2015

Additions to ExxonMobil’s proved reserves in 2015 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 3-D and 4-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 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 a member currently serves 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 2015, approximately 6.8 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 27 percent of the 24.8 GOEB reported in proved reserves. This compares to the 8.8 GOEB of proved undeveloped reserves reported at the end of 2014. During the year, ExxonMobil conducted development activities in over 100 fields that resulted in the transfer of approximately 2.7 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related to Kearl Expansion project start-up and drilling activity in the United States. Mainly due to low prices during 2015, the Corporation reclassified approximately 1 GOEB of proved undeveloped reserves, primarily natural gas reserves in the United States, which no longer meet the SEC definition of proved reserves.

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 recording proved undeveloped reserves to the start of production. However, the development time for large and complex projects can exceed five years. During 2015, extensions and purchases primarily related to United States unconventional and Abu Dhabi drilling added approximately 1.7 GOEB of proved undeveloped reserves. Overall, investments of $19.4 billion were made by the Corporation during 2015 to progress the development of reported proved undeveloped reserves, including $17 billion for oil and gas producing activities and an additional $2.4 billion for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities. These investments represented 76 percent of the $25.4 billion in total reported Upstream capital and exploration expenditures.

Proved undeveloped reserves in Australia, the United States, Kazakhstan, the Netherlands, Qatar, and Nigeria 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 natural gas price levels. Of the proved undeveloped reserves that have been reported for five or more years, 84 percent are contained in the aforementioned countries. The largest of these is related to LNG/Gas projects in Australia, where construction of the Gorgon LNG project 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 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.

	2015		2014		2013	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	326	86	304	85	283	85
Canada/South America	47	8	52	9	57	10
Europe	173	28	151	28	157	27
Africa	511	18	469	20	451	18
Asia	346	29	293	26	313	30
Australia/Oceania	33	17	39	20	29	19
Total Consolidated Subsidiaries	1,436	186	1,308	188	1,290	189
Equity Companies						
United States	61	3	63	2	61	2
Europe	3	-	5	-	6	-
Asia	241	68	236	69	373	68
Total Equity Companies	305	71	304	71	440	70
Total crude oil and natural gas liquids production	1,741	257	1,612	259	1,730	259
Bitumen production						
Consolidated Subsidiaries						
Canada/South America	289		180		148	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/South America	58		60		65	
Total liquids production	2,345		2,111		2,202	
	(millions of cubic feet daily)					
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	3,116		3,374		3,530	
Canada/South America *(1)*	261		310		354	
Europe	1,110		1,226		1,294	
Africa	5		4		6	
Asia	1,080		1,067		1,180	
Australia/Oceania	677		512		351	
Total Consolidated Subsidiaries	6,249		6,493		6,715	

Equity Companies			
United States	31	30	15
Europe	1,176	1,590	1,957
Asia	3,059	3,032	3,149
Total Equity Companies	4,266	4,652	5,121
Total natural gas production available for sale	10,515	11,145	11,836
	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production	4,097	3,969	4,175

(1) South America includes natural gas production available for sale for 2015, 2014 and 2013 of 21 million, 21 million, and 28 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 2015			*(dollars per unit)*				
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	41.87	44.30	49.04	51.01	48.30	49.56	47.75
NGL, per barrel	16.96	21.91	27.50	33.41	21.14	29.75	22.16
Natural gas, per thousand cubic feet	1.65	1.78	6.47	1.57	2.02	5.13	2.95
Bitumen, per barrel	-	25.07	-	-	-	-	25.07
Synthetic oil, per barrel	-	48.15	-	-	-	-	48.15
Average production costs, per oil-equivalent barrel - total	12.50	22.68	15.86	10.31	7.71	8.86	12.97
Average production costs, per barrel - bitumen	-	19.20	-	-	-	-	19.20
Average production costs, per barrel - synthetic oil	-	41.83	-	-	-	-	41.83
Equity Companies							
Average production prices							
Crude oil, per barrel	46.34	-	46.05	-	48.44	-	47.99
NGL, per barrel	15.37	-	-	-	32.36	-	31.75
Natural gas, per thousand cubic feet	2.05	-	6.27	-	5.83	-	5.92
Average production costs, per oil-equivalent barrel - total	22.15	-	7.75	-	1.41	-	3.89
Total							
Average production prices							
Crude oil, per barrel	42.58	44.30	48.97	51.01	48.36	49.56	47.79
NGL, per barrel	16.92	21.91	27.50	33.41	28.94	29.75	24.77
Natural gas, per thousand cubic feet	1.65	1.78	6.37	1.57	4.84	5.13	4.16
Bitumen, per barrel	-	25.07	-	-	-	-	25.07
Synthetic oil, per barrel	-	48.15	-	-	-	-	48.15
Average production costs, per oil-equivalent barrel - total	13.16	22.68	13.09	10.31	3.96	8.86	10.56
Average production costs, per barrel - bitumen	-	19.20	-	-	-	-	19.20
Average production costs, per barrel - synthetic oil	-	41.83	-	-	-	-	41.83
During 2014							
Consolidated Subsidiaries							
Average production prices							

Crude oil, per barrel	84.00	86.46	96.43	97.46	95.27	95.56	93.21
NGL, per barrel	39.70	51.86	53.68	65.21	40.81	56.77	47.07
Natural gas, per thousand cubic feet	3.61	3.96	8.18	2.61	3.71	5.87	4.68
Bitumen, per barrel	-	62.68	-	-	-	-	62.68
Synthetic oil, per barrel	-	89.76	-	-	-	-	89.76
Average production costs, per oil-equivalent barrel - total	13.35	33.03	22.29	12.58	8.64	11.05	15.94
Average production costs, per barrel - bitumen	-	32.66	-	-	-	-	32.66
Average production costs, per barrel - synthetic oil	-	55.32	-	-	-	-	55.32
Equity Companies							
Average production prices							
Crude oil, per barrel	91.24	-	88.68	-	93.42	-	92.89
NGL, per barrel	38.77	-	-	-	65.31	-	64.41
Natural gas, per thousand cubic feet	4.54	-	8.28	-	10.00	-	9.38
Average production costs, per oil-equivalent barrel - total	24.34	-	6.10	-	1.85	-	4.22
Total							
Average production prices							
Crude oil, per barrel	85.23	86.46	96.17	97.46	94.44	95.56	93.15
NGL, per barrel	39.68	51.86	53.68	65.21	58.52	56.77	51.84
Natural gas, per thousand cubic feet	3.62	3.96	8.23	2.61	8.36	5.87	6.64
Bitumen, per barrel	-	62.68	-	-	-	-	62.68
Synthetic oil, per barrel	-	89.76	-	-	-	-	89.76
Average production costs, per oil-equivalent barrel - total	14.10	33.03	15.59	12.58	4.44	11.05	12.55
Average production costs, per barrel - bitumen	-	32.66	-	-	-	-	32.66
Average production costs, per barrel - synthetic oil	-	55.32	-	-	-	-	55.32

	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

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

	2015	2014	2013
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	-	3	8
Canada/South America	1	3	4
Europe	1	1	-
Africa	1	2	2
Asia	2	-	-
Australia/Oceania	1	-	-
Total Consolidated Subsidiaries	6	9	14
Equity Companies			
United States	-	-	-
Europe	1	2	1
Asia	-	-	1
Total Equity Companies	1	2	2
Total productive exploratory wells drilled	7	11	16
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	1	2	2
Canada/South America	-	1	4
Europe	2	1	1
Africa	-	1	-
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	3	5	7
Equity Companies			
United States	1	2	1
Europe	1	-	-
Asia	-	-	-
Total Equity Companies	2	2	1
Total dry exploratory wells drilled	5	7	8

	2015	2014	2013
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	692	721	755
Canada/South America	53	178	201
Europe	10	8	13
Africa	23	41	33
Asia	14	19	30
Australia/Oceania	4	5	3
Total Consolidated Subsidiaries	796	972	1,035
Equity Companies			
United States	390	340	328
Europe	1	2	2
Asia	2	1	8
Total Equity Companies	393	343	338
Total productive development wells drilled	1,189	1,315	1,373
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	5	6	5
Canada/South America	-	3	-
Europe	3	1	2
Africa	1	-	-
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	9	10	7
Equity Companies			
United States	-	-	-
Europe	-	1	1
Asia	-	-	-
Total Equity Companies	-	1	1
Total dry development wells drilled	9	11	8
Total number of net wells drilled	1,210	1,344	1,405

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 2015, the company's share of net production of synthetic crude oil was 58 thousand barrels per day and share of net acreage was 63 thousand acres in the Athabasca oil sands deposit.

Kearl Operations. Kearl 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 49 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 bitumen extraction and froth treatment trains. 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 and rail. During 2015, average net production at Kearl was 149 thousand barrels per day. The Kearl Expansion project was completed and started up in 2015, adding additional capacity of 110 thousand barrels of bitumen per day.

5. Present Activities

A. Wells Drilling

	Year-End 2015		Year-End 2014	
	Gross	**Net**	**Gross**	**Net**
Wells Drilling				
Consolidated Subsidiaries				
United States	860	379	1,120	442
Canada/South America	15	10	35	29
Europe	14	6	18	8
Africa	23	7	33	12
Asia	65	18	90	26
Australia/Oceania	3	1	10	4
Total Consolidated Subsidiaries	980	421	1,306	521
Equity Companies				
United States	18	3	31	6
Europe	9	3	4	1
Asia	1	-	1	-
Total Equity Companies	28	6	36	7
Total gross and net wells drilling	1,008	427	1,342	528

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2015 acreage holdings totaled 14.0 million net acres, of which 1.3 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During the year, 1,063.2 net exploration and development wells were completed in the inland lower 48 states. Development activities focused on liquids-rich opportunities in the onshore U.S., primarily in the Permian Basin of West Texas and New Mexico and the Bakken oil play in North Dakota and Montana. In addition, gas development activities continued in the Marcellus Shale of Pennsylvania and West Virginia and the Utica Shale of Ohio.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2015 was 1.2 million acres. A total of 3.5 net development wells were completed during the year. The deepwater Hadrian South project and the non-operated Lucius project started up in 2015. ExxonMobil continued development activities on the Heidelberg and Julia Phase 1 projects. Offshore California 1.0 net development well was completed.

Participation in Alaska production and development continued with a total of 20.9 net development wells completed. Development activities continued on the Point Thomson project.

CANADA / SOUTH AMERICA

Canada

Oil and Gas Operations: ExxonMobil's year-end 2015 acreage holdings totaled 6.2 million net acres, of which 1.9 million net acres were offshore. A total of 11.1 net exploration and development wells were completed during the year. Development activities continued on the Hebron project during 2015.

In Situ Bitumen Operations: ExxonMobil's year-end 2015 in situ bitumen acreage holdings totaled 0.7 million net onshore acres. A total of 41.0 net development wells were completed during the year. The Cold Lake Nabiye Expansion project started up in 2015.

Argentina

ExxonMobil's net acreage totaled 0.9 million onshore acres at year-end 2015, and there were 1.0 net development wells completed during the year.

EUROPE

Germany

A total of 4.8 million net onshore acres were held by ExxonMobil at year-end 2015, with 0.7 net development wells completed during the year.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.5 million acres at year-end 2015, of which 1.2 million acres were onshore. A total of 3.5 net exploration and development wells were completed during the year.

Norway

ExxonMobil's net interest in licenses at year-end 2015 totaled approximately 0.2 million acres, all offshore. A total of 6.8 net exploration and development wells were completed in 2015. The non-operated Aasgard Subsea Compression project started up in 2015.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2015 totaled approximately 0.5 million acres, all offshore. A total of 5.1 net development wells were completed during the year.

AFRICA

Angola

ExxonMobil's net acreage totaled 0.4 million offshore acres at year-end 2015, with 3.6 net development wells completed during the year. On Block 15, the Kizomba Satellites Phase 2 project started up in 2015. On Block 32, development activities continued on the Kaombo Split Hub project.

Chad

ExxonMobil's net year-end 2015 acreage holdings consisted of 46 thousand onshore acres, with 15.6 net development wells completed during the year.

Equatorial Guinea

ExxonMobil's acreage totaled 0.3 million net offshore acres at year-end 2015, with 2.3 net development wells completed during the year. In 2015, ExxonMobil acquired deepwater acreage in Block EG 06.

Nigeria

ExxonMobil's net acreage totaled 1.1 million offshore acres at year-end 2015, with 2.9 net exploration and development wells completed during the year. In 2015, ExxonMobil acquired deepwater acreage in Block OPL 247. The deepwater Erha North Phase 2 project started up, and development drilling continued on the deepwater Usan project in 2015.

ASIA

Azerbaijan

At year-end 2015, ExxonMobil's net acreage totaled 9 thousand offshore acres. A total of 0.9 net development wells were completed during the year.

Indonesia

At year-end 2015, ExxonMobil had 0.5 million net acres, 0.4 million net acres offshore and 0.1 million net acres onshore, with 3.2 net development wells completed during the year. In 2015, acreage was relinquished in the North Sumatra and Arun fields. The Banyu Urip onshore central processing facility started up in 2015.

Iraq

At year-end 2015, ExxonMobil's onshore acreage was 0.6 million net acres. West Qurna Phase 1 oil field rehabilitation activities continued during 2015 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. In the Kurdistan Region of Iraq, after operations were temporarily suspended due to security concerns in the region during 2014, ExxonMobil resumed its seismic program and exploration drilling in 2015, with 1.6 net exploration wells completed during the year.

Kazakhstan

ExxonMobil's net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2015. A total of 3.7 net development wells were completed during 2015. Following a brief production period in 2013, Kashagan operations were suspended due to a leak in the onshore section of the gas pipeline. Working with our partners, activities are under way to replace both the oil and gas pipelines.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.2 million net acres offshore at year-end 2015. During the year, a total of 4.0 net development wells were completed.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil's net acreage totaled 65 thousand acres offshore at year-end 2015. ExxonMobil participated in 62.2 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 2015.

Russia

ExxonMobil’s net acreage holdings in Sakhalin at year-end 2015 were 85 thousand acres, all offshore. A total of 1.5 net development wells were completed. The Arkutun-Dagi project started up, and development activities continued on the Odoptu Stage 2 project in 2015.

At year-end 2015, ExxonMobil’s net acreage in the Rosneft joint venture agreements for the Kara, Laptev, Chukchi and Black Seas was 63.6 million acres, all offshore. ExxonMobil and Rosneft formed a joint venture to evaluate the development of tight-oil reserves in western Siberia in 2013. Refer to the relevant portion of “Note 7: Equity Company Information” of the Financial Section of this report for additional information on the Corporation’s participation in Rosneft joint venture activities.

Thailand

ExxonMobil’s net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2015.

United Arab Emirates

ExxonMobil’s net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2015. During the year, a total of 3.6 net development wells were completed. Development activities continued on the Upper Zakum 750 project.

AUSTRALIA / OCEANIA

Australia

ExxonMobil’s year-end 2015 acreage holdings totaled 1.5 million net offshore acres. During the year, a total of 3.1 net exploration and development wells were completed. Construction activities continued on the Gas Conditioning Plant at Longford.

Project construction and commissioning activity for the co-venturer operated Gorgon liquefied natural gas (LNG) project progressed in 2015. The project consists of a subsea infrastructure for offshore production and transportation of the gas, 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 2015, with 1.5 net development wells completed during the year. The Papua New Guinea (PNG) LNG integrated development includes gas production and processing facilities in the southern PNG Highlands, onshore and offshore pipelines, and a 6.9 million tonnes per year LNG facility near Port Moresby.

WORLDWIDE EXPLORATION

At year-end 2015, 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 12.6 million net acres were held at year-end 2015 and 4.4 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 43 million barrels of oil and 2,800 billion cubic feet of natural gas for the period from 2016 through 2018. 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.

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

A. Gross and Net Productive Wells

	Year-End 2015				Year-End 2014			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	20,662	8,334	33,657	20,307	18,424	7,939	33,149	20,398
Canada/South America	5,045	4,741	4,559	1,769	5,012	4,659	4,577	1,782
Europe	1,195	345	644	255	1,215	347	642	259
Africa	1,315	517	20	8	1,299	513	19	8
Asia	818	280	149	87	804	267	207	150
Australia/Oceania	630	138	49	23	669	157	43	21
Total Consolidated Subsidiaries	29,665	14,355	39,078	22,449	27,423	13,882	38,637	22,618
Equity Companies								
United States	14,555	5,594	4,301	493	14,571	5,605	4,365	494
Europe	13	6	570	180	57	20	567	179
Asia	121	30	125	30	110	27	125	30
Total Equity Companies	14,689	5,630	4,996	703	14,738	5,652	5,057	703
Total gross and net productive wells	44,354	19,985	44,074	23,152	42,161	19,534	43,694	23,321

There were 35,909 gross and 30,114 net operated wells at year-end 2015 and 35,446 gross and 29,870 net operated wells at year-end 2014. The number of wells with multiple completions was 1,266 gross in 2015 and 1,219 gross in 2014.

Note: Year-end 2014 consolidated subsidiaries well counts for gross and net wells in the United States were restated in regards to non-operated wells.

B. Gross and Net Developed Acreage

	Year-End 2015		Year-End 2014	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	14,827	9,327	14,777	9,367
Canada/South America *(1)*	3,335	2,122	3,515	2,242
Europe	3,275	1,473	3,337	1,506
Africa	2,493	866	2,286	815
Asia	1,934	562	1,817	551
Australia/Oceania	2,123	781	2,123	758
Total Consolidated Subsidiaries	27,987	15,131	27,855	15,239
Equity Companies				
United States	939	209	949	208
Europe	4,278	1,335	4,342	1,356
Asia	628	155	628	156
Total Equity Companies	5,845	1,699	5,919	1,720
Total gross and net developed acreage	33,832	16,830	33,774	16,959

(1) Includes developed acreage in South America of 213 gross and 109 net thousands of acres for 2015 and 213 gross and 109 net thousands of acres for 2014.

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 2015		Year-End 2014	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	9,353	4,358	10,262	4,894
Canada/South America *(1)*	19,328	10,113	16,100	12,250
Europe	10,073	5,444	10,601	5,636
Africa	10,586	5,306	22,143	15,020
Asia	6,888	3,959	17,437	13,016
Australia/Oceania	5,629	1,902	6,653	2,013
Total Consolidated Subsidiaries	61,857	31,082	83,196	52,829
Equity Companies				
United States	259	92	350	118
Europe	-	-	-	-
Asia	191,147	63,633	191,146	63,632
Total Equity Companies	191,406	63,725	191,496	63,750

Total gross and net undeveloped acreage	253,263	94,807	274,692	116,579

(1) Includes undeveloped acreage in South America of 10,634 gross and 4,970 net thousands of acres for 2015 and 9,056 gross and 8,083 net thousands of acres for 2014.

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 exploration and production rights are acquired from mineral interest owners through a lease. Mineral interest owners include the Federal and State governments, as well as private mineral interest owners. Leases typically 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 regarding private property, 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 Hydrocarbon Law was amended in December 2014. The onshore concession terms granted prior to the amendment are up to six years, divided into three potential exploration periods, with an optional extension for up to one year depending on the classification of the area. Pursuant to the amended law, the production term for a conventional production concession would be 25 years, and 35 years for an unconventional concession, with unlimited ten-year extensions possible, once a field has been developed.

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 up to 50 years at the discretion of the government.

Equatorial Guinea

Exploration, development and production activities are governed by production sharing contracts (PSCs) negotiated with the State Ministry of Mines, Industry and Energy. A new PSC was signed in 2015; the initial exploration period is five years for oil and gas, with multi-year extensions available at the discretion of the Ministry and limited relinquishments in the absence of commercial discoveries. The production period for crude oil ranges from 25 to 30 years, while the production period for natural gas ranges from 25 to 50 years.

Nigeria

Exploration and production activities in the deepwater offshore areas are typically governed by production sharing contracts (PSCs) with the national oil company, the Nigerian National Petroleum Corporation (NNPC). NNPC typically 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 that can be divided into multiple 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, while in all other areas the licenses are for five years. 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. Commercial terms applicable to the existing joint venture oil production are defined by the Petroleum Profits Tax Act.

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. By presidential decree, SKKMIGAS became the interim successor to BPMIGAS. 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 (PSCs) negotiated with the regional government of Kurdistan in 2011. The exploration term is for five years, with extensions available as provided by the PSCs and at the discretion of the regional government of Kurdistan. 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

Production activities are governed by production sharing contracts (PSCs) negotiated with the national oil company. The PSCs have terms ranging up to 29 years. All extensions are subject to the national oil company's prior written approval. The total production period is 15 to 29 years, depending on the provisions of the respective contract.

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. Due to force majeure events, the development period has been extended beyond its original expiration date by an additional 400 days, with the possibility of further extensions due to ongoing force majeure events.

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, Laptev, Chukchi and Black Seas are governed by joint venture agreements concluded with Rosneft in 2013 and 2014 that cover certain of Rosneft's offshore licenses. The Kara Sea licenses covered by the joint venture agreements concluded in 2013 extend through 2040 and include an exploration period through 2020. Additional licenses in the Kara, Laptev and Chukchi Seas covered by the joint venture agreements concluded in 2014 extend through 2043 and include an exploration period through 2023. The Kara, Laptev and Chukchi Sea licenses require 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. Refer to the relevant portion of "Note 7: Equity Company Information" of the Financial Section of this report for additional information on the Corporation's participation in Rosneft joint venture activities.

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

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 2015 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMobil Interest %
United States			
Torrance	California	150	100
Joliet	Illinois	236	100
Baton Rouge	Louisiana	503	100
Billings	Montana	60	100
Baytown	Texas	561	100
Beaumont	Texas	345	100
Total United States		1,855	
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	239	82.9
Karlsruhe	Germany	78	25
Augusta	Italy	198	100
Trecate	Italy	132	74.8
Rotterdam	Netherlands	191	100
Slagen	Norway	116	100
Fawley	United Kingdom	261	100
Total Europe		1,655	
Asia Pacific			
Altona	Australia	78	100
Fujian	China	67	25
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	167	66
Total Asia Pacific		904	
Middle East			
Yanbu	Saudi Arabia	200	50
Total Worldwide		5,035	

(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. The listing excludes refineries owned through cost companies in Japan and New Zealand, and the Laffan Refinery in Qatar for which results are reported in the Upstream segment.

(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 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 2015

United States			
	Owned/leased		-
	Distributors/resellers		9,617
		Total United States	9,617
Canada			
	Owned/leased		474
	Distributors/resellers		1,281
		Total Canada	1,755
Europe			
	Owned/leased		2,438
	Distributors/resellers		3,612
		Total Europe	6,050
Asia Pacific			
	Owned/leased		645
	Distributors/resellers		795
		Total Asia Pacific	1,440
Latin America			
	Owned/leased		9
	Distributors/resellers		745
		Total Latin America	754
Middle East/Africa			
	Owned/leased		372
	Distributors/resellers		263
		Total Middle East/Africa	635
Worldwide			
	Owned/leased		3,938
	Distributors/resellers		16,313
		Total Worldwide	20,251

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 2015 *(1)(2)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
North America						
Baton Rouge	Louisiana	1.0	1.3	0.4	-	100
Baytown	Texas	2.2	-	0.7	0.7	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	1.0	
Europe						
Antwerp	Belgium	-	0.4	-	-	100
Fife	United Kingdom	0.4	-	-	-	50
Gravenchon	France	0.4	0.4	0.3	-	100
Meerhout	Belgium	-	0.5	-	-	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	0.3	0.2	0.2	0.2	25
Singapore	Singapore	1.9	1.9	0.9	1.0	100
Sriracha	Thailand	-	-	-	0.5	66
Total Asia Pacific		2.2	2.1	1.1	1.7	
Total Worldwide		9.0	8.6	2.7	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. The listing excludes cost company capacity in Japan.

Item 3. Legal Proceedings

As reported in the Corporation's Form 10-Q for the third quarter of 2015, following ExxonMobil Oil Corporation's (EMOC) self-reporting of an air emission event at the ExxonMobil Beaumont Chemical Plant, the Texas Commission on Environmental Quality (TCEQ) notified EMOC on September 17, 2015, that it was seeking a penalty of $150,000 for exceeding provisions of the Texas Administrative Code and the Texas Health and Safety Code. On December 15, 2015, the TCEQ agreed with EMOC on the duration of the event, and the parties agreed to an administrative penalty of $50,000, of which $25,000 was paid to the TCEQ on January 7, 2016. The balance will be paid for a Supplemental Environmental Project upon endorsement by the TCEQ.

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: 63

Mr. Rex W. Tillerson became a Director and President of Exxon Mobil Corporation on March 1, 2004, and was President through December 31, 2015. He became Chairman of the Board and Chief Executive Officer on January 1, 2006, positions he still holds as of the filing date.

Darren W. Woods *President*

Held current title since: January 1, 2016 Age: 51

Mr. Darren W. Woods was Vice President, Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2012. He was President of ExxonMobil Refining & Supply Company August 1, 2012 – July 31, 2014 and Vice President of Exxon Mobil Corporation August 1, 2012 – May 31, 2014. He was Senior Vice President of Exxon Mobil Corporation June 1, 2014 – December 31, 2015. He became a Director and President of Exxon Mobil Corporation on January 1, 2016, positions he still holds as of this filing date.

Mark W. Albers *Senior Vice President*

Held current title since: April 1, 2007 Age: 59

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: 62

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: 59

Mr. Andrew P. Swiger became Senior Vice President of Exxon Mobil Corporation on April 1, 2009, a position he still holds as of this filing date.

Jack P. Williams, Jr. *Senior Vice President*

Held current title since: June 1, 2014 Age: 52

Mr. Jack P. Williams, Jr. was President of XTO Energy Inc. June 25, 2010 – May 31, 2013. He was Executive Vice President of ExxonMobil Production Company June 1, 2013 – June 30, 2014. He became Senior Vice President of Exxon Mobil Corporation on June 1, 2014, 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: 64

Mr. S. Jack Balagia became Vice President and General Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

Neil A. Chapman *Vice President*

Held current title since: January 1, 2015 Age: 53

Mr. Neil A. Chapman was President of ExxonMobil Global Services Company April 4, 2007 – March 31, 2011. He was Senior Vice President, ExxonMobil Chemical Company April 1, 2011 – December 31, 2014. He became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation on January 1, 2015, 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: 54

Mr. Randy J. Cleveland 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: 62

Mr. William M. Colton became Vice President – Corporate Strategic Planning of Exxon Mobil Corporation on February 1, 2009, a position he still holds as of this filing date.

Bradley W. Corson *Vice President*

Held current title since: March 1, 2015 Age: 54

Mr. Bradley W. Corson was Regional Vice President, Europe/Caspian for ExxonMobil Production Company May 1, 2009 – April 30, 2014. He was Vice President, ExxonMobil Upstream Ventures May 1, 2014 – February 28, 2015. He became President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation on March 1, 2015, positions he still holds as of this filing date.

Neil W. Duffin *President, ExxonMobil Development Company*

Held current title since: April 13, 2007 Age: 59

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: 58

Mr. Robert S. Franklin was President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation 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: 58

Mr. Stephen M. Greenlee 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: 58

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.

David S. Rosenthal *Vice President and Controller*

Held current title since: October 1, 2008 (Vice President) Age: 59

September 1, 2014 (Controller)

Mr. David S. Rosenthal was Vice President – Investor Relations and Secretary of Exxon Mobil Corporation October 1, 2008 – August 31, 2014. He became Vice President and Controller of Exxon Mobil Corporation on September 1, 2014, positions he still holds as of this filing date.

Robert N. Schleckser *Vice President and Treasurer*

Held current title since: May 1, 2011 Age: 59

Mr. Robert N. Schleckser 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: 54

Mr. James M. Spellings, Jr. 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: 61

Mr. Thomas R. Walters 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.

Dennis G. Wascom *Vice President*

Held current title since: August 1, 2014 Age: 59

Mr. Dennis G. Wascom was Director, Refining Americas, ExxonMobil Refining & Supply Company April 1, 2009 – June 30, 2013. He was Director, Refining North America, ExxonMobil Refining & Supply Company July 1, 2013 – July 31, 2014. He became President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corporation on August 1, 2014, positions he still holds as of this filing date.

Jeffrey J. Woodbury *Vice President – Investor Relations and Secretary*

Held current title since: July 1, 2011 (Vice President) Age: 55

September 1, 2014 (Secretary)

Mr. Jeffrey J. Woodbury was Executive Vice President of ExxonMobil Development Company April 1, 2009 – June 30, 2011. He was Vice President, Safety, Security, Health and Environment of Exxon Mobil Corporation July 1, 2011 – August 31, 2014. He became Vice President – Investor Relations and Secretary of Exxon Mobil Corporation on September 1, 2014, 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.

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, 2015

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2015	2,251,296	79.78	2,251,296	
November 2015	3,845,713	81.66	3,845,713	
December 2015	3,292,255	79.01	3,292,255	
Total	9,389,264	80.28	9,389,264	(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 February 2, 2016, the Corporation stated it will continue to acquire shares to offset dilution in conjunction with benefit plans and programs, but does not plan on making purchases to reduce shares outstanding.

Item 6. Selected Financial Data

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	259,488	394,105	420,836	451,509	467,029
(1) Sales-based taxes included	*22,678*	*29,342*	*30,589*	*32,409*	*33,503*
Net income attributable to ExxonMobil	16,150	32,520	32,580	44,880	41,060
Earnings per common share	3.85	7.60	7.37	9.70	8.43
Earnings per common share - assuming dilution	3.85	7.60	7.37	9.70	8.42
Cash dividends per common share	2.88	2.70	2.46	2.18	1.85
Total assets	336,758	349,493	346,808	333,795	331,052
Long-term debt	19,925	11,653	6,891	7,928	9,322

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 24, 2016, 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, 2015. 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 (2013)* 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, 2015.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2015, 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 2016 annual meeting of shareholders (the "2016 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 2016 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 2016 Proxy Statement.

Equity Compensation Plan Information

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	31,090,370*(1)*	-	100,899,852*(2)(3)*
	-	-	-

Equity compensation plans not approved by security holders			
Total	31,090,370	-	100,899,852

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

(2) Available shares can be granted in the form of restricted stock, options, or other stock-based awards. Includes 100,324,152 shares available for award under the 2003 Incentive Program and 575,700 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.

(3) 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 2016 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 2016 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

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BUSINESS PROFILE

Financial	**Earnings After Income Taxes 2015**	**2014**	**Average Capital Employed 2015**	**2014**	**Return on Average Capital Employed 2015**	**2014**	**Capital and Exploration Expenditures 2015**	**2014**
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	(1,079)	5,197	64,086	62,403	(1.7)	8.3	7,822	9,401
Non-U.S.	8,180	22,351	105,868	102,562	7.7	21.8	17,585	23,326
Total	7,101	27,548	169,954	164,965	4.2	16.7	25,407	32,727
Downstream								
United States	1,901	1,618	7,497	6,070	25.4	26.7	1,039	1,310
Non-U.S.	4,656	1,427	15,756	17,907	29.6	8.0	1,574	1,724
Total	6,557	3,045	23,253	23,977	28.2	12.7	2,613	3,034
Chemical								
United States	2,386	2,804	7,696	6,121	31.0	45.8	1,945	1,690
Non-U.S.	2,032	1,511	16,054	16,076	12.7	9.4	898	1,051
Total	4,418	4,315	23,750	22,197	18.6	19.4	2,843	2,741
Corporate and financing	(1,926)	(2,388)	(8,202)	(8,029)	-	-	188	35
Total	16,150	32,520	208,755	203,110	7.9	16.2	31,051	38,537

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

Operating	**2015**	**2014**		**2015**	**2014**
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	476	454	United States	1,709	1,809
Non-U.S.	1,869	1,657	Non-U.S.	2,723	2,667
Total	2,345	2,111	Total	4,432	4,476
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales *(2)*		
United States	3,147	3,404	United States	2,521	2,655
Non-U.S.	7,368	7,741	Non-U.S.	3,233	3,220
Total	10,515	11,145	Total	5,754	5,875
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	

Oil-equivalent production *(1)*	4,097	3,969	Chemical prime product sales *(2)(3)*		
			United States	9,664	9,528
			Non-U.S.	15,049	14,707
			Total	24,713	24,235

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

(2) Petroleum product and chemical prime product sales data reported net of purchases/sales contracts with the same counterparty.

(3) Prime product sales are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil´s share of equity company volumes and finished-product transfers to the Downstream.

FINANCIAL SUMMARY

	2015	2014	2013	2012	2011
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	259,488	394,105	420,836	451,509	467,029
Earnings					
Upstream	7,101	27,548	26,841	29,895	34,439
Downstream	6,557	3,045	3,449	13,190	4,459
Chemical	4,418	4,315	3,828	3,898	4,383
Corporate and financing	(1,926)	(2,388)	(1,538)	(2,103)	(2,221)
Net income attributable to ExxonMobil	16,150	32,520	32,580	44,880	41,060
Earnings per common share	3.85	7.60	7.37	9.70	8.43
Earnings per common share – assuming dilution	3.85	7.60	7.37	9.70	8.42
Cash dividends per common share	2.88	2.70	2.46	2.18	1.85
Earnings to average ExxonMobil share of equity (percent)	9.4	18.7	19.2	28.0	27.3
Working capital	(11,353)	(11,723)	(12,416)	321	(4,542)
Ratio of current assets to current liabilities (times)	0.79	0.82	0.83	1.01	0.94
Additions to property, plant and equipment	27,475	34,256	37,741	35,179	33,638
Property, plant and equipment, less allowances	251,605	252,668	243,650	226,949	214,664
Total assets	336,758	349,493	346,808	333,795	331,052
Exploration expenses, including dry holes	1,523	1,669	1,976	1,840	2,081
Research and development costs	1,008	971	1,044	1,042	1,044
Long-term debt	19,925	11,653	6,891	7,928	9,322
Total debt	38,687	29,121	22,699	11,581	17,033
Fixed-charge coverage ratio (times)	17.6	46.9	55.7	62.4	53.4
Debt to capital (percent)	18.0	13.9	11.2	6.3	9.6
Net debt to capital (percent) *(2)*	16.5	11.9	9.1	1.2	2.6
ExxonMobil share of equity at year-end	170,811	174,399	174,003	165,863	154,396
ExxonMobil share of equity per common share	41.10	41.51	40.14	36.84	32.61
Weighted average number of common shares outstanding (millions)	4,196	4,282	4,419	4,628	4,870
Number of regular employees at year-end (thousands) *(3)*	73.5	75.3	75.0	76.9	82.1

CORS employees not included above (thousands) *(4)*	2.1	8.4	9.8	11.1	17.0

(1) Sales and other operating revenue includes sales-based taxes of $22,678 million for 2015, $29,342 million for 2014, $30,589 million for 2013, $32,409 million for 2012 and $33,503 million for 2011.

(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	**2015**	**2014**	**2013**
		(millions of dollars)	
Net cash provided by operating activities	30,344	45,116	44,914
Proceeds associated with sales of subsidiaries, property, plant and equipment,			
and sales and returns of investments	2,389	4,035	2,707
Cash flow from operations and asset sales	32,733	49,151	47,621

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	**2015**	**2014**	**2013**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	336,758	349,493	346,808
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(35,214)	(47,165)	(55,916)
Total long-term liabilities excluding long-term debt	(86,047)	(92,143)	(87,698)
Noncontrolling interests share of assets and liabilities	(8,286)	(9,099)	(8,935)
Add ExxonMobil share of debt-financed equity company net assets	4,447	4,766	6,109
Total capital employed	211,658	205,852	200,368

Total corporate sources: debt and equity perspective			
Notes and loans payable	18,762	17,468	15,808
Long-term debt	19,925	11,653	6,891
ExxonMobil share of equity	170,811	174,399	174,003
Less noncontrolling interests share of total debt	(2,287)	(2,434)	(2,443)
Add ExxonMobil share of equity company debt	4,447	4,766	6,109
Total capital employed	211,658	205,852	200,368

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	**2015**	**2014**	**2013**
		(millions of dollars)	
Net income attributable to ExxonMobil	16,150	32,520	32,580
Financing costs (after tax)			
Gross third-party debt	(362)	(140)	(163)
ExxonMobil share of equity companies	(170)	(256)	(239)
All other financing costs – net	88	(68)	83
Total financing costs	(444)	(464)	(319)
Earnings excluding financing costs	16,594	32,984	32,899
Average capital employed	208,755	203,110	191,575
Return on average capital employed – corporate total	7.9%	16.2%	17.2%

QUARTERLY INFORMATION

	2015					2014				
	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)*					
natural gas liquids, synthetic oil and bitumen	2,277	2,291	2,331	2,481	2,345	2,148	2,048	2,065	2,182	2,111
Refinery throughput	4,546	4,330	4,457	4,395	4,432	4,509	4,454	4,591	4,349	4,476
Petroleum product sales *(1)*	5,814	5,737	5,788	5,679	5,754	5,817	5,841	5,999	5,845	5,875
Natural gas production					*(millions of cubic feet daily)*					
available for sale	11,828	10,128	9,524	10,603	10,515	12,016	10,750	10,595	11,234	11,145
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(2)*	4,248	3,979	3,918	4,248	4,097	4,151	3,840	3,831	4,054	3,969
					(thousands of metric tons)					
Chemical prime product sales *(1) (3)*	6,069	6,078	6,082	6,484	24,713	6,128	6,139	6,249	5,719	24,235
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(4)*	64,758	71,360	65,679	57,691	259,488	101,312	105,719	103,206	83,868	394,105
Gross profit *(5)*	19,030	20,362	20,247	16,211	75,850	29,166	28,746	28,825	23,240	109,977
Net income attributable to ExxonMobil	4,940	4,190	4,240	2,780	16,150	9,100	8,780	8,070	6,570	32,520
Per share data					*(dollars per share)*					
Earnings per common share *(6)*	1.17	1.00	1.01	0.67	3.85	2.10	2.05	1.89	1.56	7.60
Earnings per common share – assuming dilution *(6)*	1.17	1.00	1.01	0.67	3.85	2.10	2.05	1.89	1.56	7.60
Dividends per common share	0.69	0.73	0.73	0.73	2.88	0.63	0.69	0.69	0.69	2.70
Common stock prices										
High	93.45	90.09	83.53	87.44	93.45	101.22	104.61	104.76	97.20	104.76
Low	82.68	82.80	66.55	73.03	66.55	89.25	96.24	93.62	86.19	86.19

(1) Petroleum product and chemical prime product sales data reported net of purchases/sales contracts with the same counterparty.

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

(3) Prime product sales are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream.

(4) Includes amounts for sales-based taxes.

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

(6) 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 419,510 registered shareholders of ExxonMobil common stock at December 31, 2015. At January 31, 2016, the registered shareholders of ExxonMobil common stock numbered 418,587.

On January 27, 2016, the Corporation declared a $0.73 dividend per common share, payable March 10, 2016.

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

FUNCTIONAL EARNINGS	2015	2014	2013
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	(1,079)	5,197	4,191
Non-U.S.	8,180	22,351	22,650
Downstream			
United States	1,901	1,618	2,199
Non-U.S.	4,656	1,427	1,250
Chemical			
United States	2,386	2,804	2,755
Non-U.S.	2,032	1,511	1,073
Corporate and financing	(1,926)	(2,388)	(1,538)
Net income attributable to ExxonMobil (U.S. GAAP)	16,150	32,520	32,580
Earnings per common share	3.85	7.60	7.37
Earnings per common share – assuming dilution	3.85	7.60	7.37

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.

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future financial and operating 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 and resulting price impacts; the outcome of commercial negotiations; the impact of fiscal and commercial terms; 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. The company's integrated business model, with significant investments in Upstream, Downstream and Chemical segments, reduces the Corporation's risk from changes in commodity prices. 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 evaluated 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.

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

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2040, the world's population is projected to grow to approximately 9 billion people, or about 1.8 billion more than in 2014. 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 25 percent from 2014 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 30 percent from 2014 to 2040. The growth in transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Nearly all the world's transportation fleets will continue to run on liquid fuels, which 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 65 percent from 2014 to 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. Today, coal fired generation provides about 40 percent of the world's electricity, but by 2040 its share is likely to decline to about 30 percent, in part as a result of policies to improve air quality and reduce greenhouse gas emissions and the risks of climate change. From 2014 to 2040, the amount of electricity generated using natural gas, nuclear power, and renewables are all likely to double. By 2040, coal, natural gas and renewables are projected to be generating approximately the same share of electricity worldwide, although significant differences will exist across regions reflecting a wide range of factors including the cost and availability of energy types.

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 projected to grow to approximately 112 million barrels of oil equivalent per day, an increase of about 20 percent from 2014. Globally, crude production from traditional conventional sources will likely decrease slightly through 2040, with significant development activity mostly offsetting natural declines from these fields. However, this decrease is expected to be more than offset by rising production from a 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 it is expected to be the fastest-growing major fuel source from 2014 to 2040, meeting about 40 percent of global energy demand growth. Global natural gas demand is expected to rise about 50 percent from 2014 to 2040, with about 45 percent of that increase in the Asia Pacific region. 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. In total, about 60 percent of the growth in natural gas supplies is expected to be from unconventional sources. However, we expect conventionally-produced natural gas to remain the cornerstone of supply, meeting about two thirds of global demand in 2040. The worldwide liquefied natural gas (LNG) market is expected to almost triple by 2040, with much of this supply expected to meet rising demand in Asia Pacific.

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 in the 2025 2030 timeframe. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to about 20 percent. Nuclear power is projected to grow significantly, as many nations are likely to expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is likely to reach about 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase rapidly, growing close to 250 percent from 2014 to 2040, when they will be approaching 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 oil and natural

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gas supply requirements worldwide over the period 2015 2040 will be about $25 trillion (measured in 2014 dollars) or approximately $1 trillion per year on average.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. For many years, the Corporation has taken into account policies established to reduce energy related greenhouse gas emissions in its long-term *Outlook for Energy*, which is used as a foundation for assessing the business environment and business strategies and investments. The climate accord reached at the recent Conference of the Parties (COP 21) in Paris set many new goals, and while many related policies are still emerging, the *Outlook for Energy* continues to anticipate that such policies will increase the cost of carbon dioxide emissions over time. For purposes of the *Outlook for Energy*, we continue to assume that governments will enact policies that impose rising costs on energy related CO_2 emissions, which we assume will reach an implied cost in OECD nations of about $80 per tonne in 2040. China and other leading non OECD nations are expected to trail OECD policy initiatives. Nevertheless, as people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need. Thus, all practical and economically viable energy sources, both conventional and unconventional, will be needed to continue meeting global energy needs – because of the scale of worldwide energy demand.

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 capturing material and accretive opportunities to continually high-grade the resource portfolio, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, pursuing productivity and efficiency gains, growing profitable 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 and in the type of opportunities from which volumes are produced. Oil equivalent production from North America is expected to increase over the next several years based on current capital activity plans, contributing over a third of total production. Further, the proportion of our global production from resource types utilizing specialized technologies such as arctic, deepwater, and unconventional drilling and production systems, as well as LNG, is also expected to grow, becoming a slight majority of production in the next few years. 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 anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; changes in the amount and timing of capital investments that may vary depending on the oil and gas price environment; and other factors described in Item 1A. Risk Factors.

The upstream industry environment has been challenged throughout 2015 with abundant crude oil supply causing crude oil prices to decrease to levels not seen since 2004, while natural gas prices remained depressed. However, current market conditions are not necessarily indicative of future conditions. The markets for crude oil and natural gas have a history of significant price volatility. ExxonMobil believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of global economic growth. On the supply side, prices may be significantly impacted by political events, the actions of OPEC and other large government resource owners, and other factors. To manage the risks associated with price, ExxonMobil evaluates annual plans and all investments across a wide range of price scenarios. The Corporation’s assessment is that its operations will exhibit strong performance over the long term. This is the outcome of disciplined investment, cost management, asset enhancement programs, and application of advanced technologies.

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.

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ExxonMobil's fundamental Downstream business strategies competitively position the company across a range of market conditions. These strategies include targeting best in class operations in all aspects of the business, maximizing value from advanced technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, operating efficiently and effectively, and providing quality, valued and differentiated products and services to customers.

ExxonMobil's operating results, as noted in Item 2. Properties, reflect 23 refineries, located in 14 countries, with distillation capacity of 5 million barrels per day and lubricant basestock manufacturing capacity of 136 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 improved in 2015. Growth in global demand, stimulated by lower prices for crude oil and transportation fuels, resulted in higher refinery utilization and margins, particularly in Europe and Asia Pacific. Refineries in North America continue to benefit from lower raw material and energy costs due to the abundant supply of crude oil and natural gas. In the near term, we see variability in refining margins, with some regions seeing weaker margins as new capacity additions are expected to outpace growth in global demand for our products, which can also be affected by global economic conditions and regulatory changes.

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 subject to intense competition as new capacity additions outpace the growth in global demand. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

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 Downstream business

In the retail fuels marketing business, competition has caused inflation adjusted margins to decline. In 2015, ExxonMobil expanded its branded retail site network and progressed the multi year transition of the direct served (i.e., dealer, company operated) retail network in portions of Europe to a more capital efficient Branded Wholesaler model. The company's lubricants business continues to grow, leveraging world class brands and integration with industry leading basestock refining capability. ExxonMobil remains a market leader in the high value synthetic lubricants sector, despite increasing competition.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. In 2015, the company divested its 50 percent share of Chalmette Refining, LLC, and reached an agreement for the sale of the refinery in Torrance, California, with change-in-control expected by mid-2016. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. In 2015, construction continued on a new delayed coker unit at the refinery in Antwerp, Belgium, to upgrade low value bunker fuel into higher value diesel products. Funding was approved for the construction of a proprietary hydrocracker at the refinery in Rotterdam, Netherlands, to produce higher value ultra low sulfur diesel and Group II basestocks. The company completed an expansion of lubricant basestock capacity at the refinery in Baytown, Texas. Finished lubricant plant expansions in China and Finland were completed, and an expansion in Singapore is underway to support demand growth for finished lubricants and greases in key markets.

Chemical

Worldwide petrochemical demand continued to improve in 2015, led by growing demand from Asia Pacific manufacturers of industrial and consumer products. North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low cost feedstock and energy. Specialty product margins improved in 2015, but continued to be impacted by new industry capacity.

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 2015, we neared completion of the specialty elastomers project at our joint venture facility in Al-Jubail, Saudi Arabia. Construction continued on a major expansion at our Texas facilities, including a new world-scale ethane cracker and polyethylene lines, to capitalize on low-cost feedstock and energy supplies in North America and to meet rapidly growing demand for premium polymers. Construction of new halobutyl rubber and hydrocarbon resin units also progressed in Singapore to further extend our specialty product capacity in Asia Pacific.

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

REVIEW OF 2015 AND 2014 RESULTS

	2015	2014	2013
		(millions of dollars)	
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	16,150	32,520	32,580

Upstream

	2015	2014	2013
		(millions of dollars)	
Upstream			
United States	(1,079)	5,197	4,191
Non-U.S.	8,180	22,351	22,650
Total	7,101	27,548	26,841

2015

Upstream earnings were $7,101 million, down $20,447 million from 2014. Lower realizations decreased earnings by $18.8 billion. Favorable volume and mix effects increased earnings by $810 million, including contributions from new developments. All other items decreased earnings by $2.4 billion, primarily due to lower asset management gains and approximately $500 million of lower favorable one time tax effects, partly offset by lower expenses of about $230 million. On an oil equivalent basis, production of 4.1 million barrels per day was up 3.2 percent compared to 2014. Liquids production of 2.3 million barrels per day increased 234,000 barrels per day, with project ramp up and entitlement effects partly offset by field decline. Natural gas production of 10.5 billion cubic feet per day decreased 630 million cubic feet per day from 2014 as regulatory restrictions in the Netherlands and field decline were partly offset by project ramp up, work programs and entitlement effects.U.S. Upstream earnings declined $6,276 million from 2014 to a loss of $1,079 million in 2015. Earnings outside the U.S. were $8,180 million, down $14,171 million from the prior year.

2014

Upstream earnings were $27,548 million, up $707 million from 2013. Lower prices decreased earnings by $2 billion. Favorable volume effects increased earnings by $510 million. All other items, primarily asset sales and favorable U.S. deferred income tax items, increased earnings by $2.2 billion. On an oil equivalent basis, production of 4 million barrels per day was down 4.9 percent compared to 2013. Excluding the impact of the expiry of the Abu Dhabi onshore concession, production decreased 1.7 percent. Liquids production of 2.1 million barrels per day decreased 91,000 barrels per day compared to 2013. The Abu Dhabi onshore concession expiry reduced volumes by 135,000 barrels per day. Excluding this impact, liquids production was up 2 percent, driven by project ramp up and work programs. Natural gas production of 11.1 billion cubic feet per day decreased 691 million cubic feet per day from 2013, as expected U.S. field decline and lower European demand were partially offset by project ramp up and work programs. Earnings from U.S. Upstream operations were $5,197 million, up $1,006 million from 2013. Earnings outside the U.S. were $22,351 million, down $299 million from the prior year.

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

Upstream Additional Information

	2015	2014
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production)*(1)*		
Prior year	3,969	4,175
Entitlements - Net Interest	(14)	(4)
Entitlements - Price / Spend / Other	168	(43)
Quotas	-	-
Divestments	(25)	(31)
United Arab Emirates Onshore Concession Expiry	(6)	(135)
Growth / Other	5	7
Current Year	4,097	3,969

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

Listed below are descriptions of ExxonMobil's volumes reconciliation factors which are provided to facilitate understanding of the terms.

Entitlements - Net Interest are changes to ExxonMobil's share of production volumes caused by non-operational changes to volume-determining factors. These factors consist of net interest changes specified in Production Sharing Contracts (PSCs) which typically occur when cumulative investment returns or production volumes achieve defined thresholds, changes in equity upon achieving pay-out in partner investment carry situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concession. Once a net interest change has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Entitlements - Price, Spend and Other are changes to ExxonMobil's share of production volumes resulting from temporary changes to non-operational volume-determining factors. These factors include changes in oil and gas prices or spending levels from one period to another. 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. For example, at higher prices, fewer barrels are required for ExxonMobil to recover its costs. These effects generally vary from period to period with field spending patterns or market prices for oil and natural gas. Such factors can also include other temporary changes in net interest as dictated by specific provisions in production agreements.

Quotas are changes in ExxonMobil's allowable production arising from production constraints imposed by countries which are members of the Organization of the Petroleum Exporting Countries (OPEC). Volumes reported in this category would have been readily producible in the absence of the quota.

Divestments are reductions in ExxonMobil's production arising from commercial arrangements to fully or partially reduce equity in a field or asset in exchange for financial or other economic consideration.

Growth and Other factors comprise all other operational and non-operational factors not covered by the above definitions that may affect volumes attributable to ExxonMobil. Such factors include, but are not limited to, production enhancements from project and work program activities, acquisitions including additions from asset exchanges, downtime, market demand, natural field decline, and any fiscal or commercial terms that do not affect entitlements.

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

Downstream

	2015	2014	2013
	(millions of dollars)		
Downstream			
United States	1,901	1,618	2,199
Non-U.S.	4,656	1,427	1,250
Total	6,557	3,045	3,449

2015

Downstream earnings of $6,557 million increased $3,512 million from 2014. Stronger margins increased earnings by $4.1 billion, while volume and mix effects decreased earnings by $200 million. All other items decreased earnings by $420 million, reflecting nearly $560 million in higher maintenance expense and about $280 million in unfavorable inventory impacts, partly offset by favorable foreign exchange effects. Petroleum product sales of 5.8 million barrels per day were 121,000 barrels per day lower than 2014. U.S. Downstream earnings were $1,901 million, an increase of $283 million from 2014. Non U.S. Downstream earnings were $4,656 million, up $3,229 million from the prior year.

2014

Downstream earnings of $3,045 million decreased $404 million from 2013. Lower margins decreased earnings by $230 million. Volume and mix effects increased earnings by $480 million. All other items, primarily unfavorable foreign exchange and tax impacts, partially offset by lower expenses, decreased earnings by $650 million. Petroleum product sales of 5.9 million barrels per day were in line with 2013. U.S. Downstream earnings were $1,618 million, a decrease of $581 million from 2013. Non U.S. Downstream earnings were $1,427 million, up $177 million from the prior year.

Chemical

	2015	2014	2013
	(millions of dollars)		
Chemical			
United States	2,386	2,804	2,755
Non-U.S.	2,032	1,511	1,073
Total	4,418	4,315	3,828

2015

Chemical earnings of $4,418 million increased $103 million from 2014. Stronger margins increased earnings by $590 million. Favorable volume and mix effects increased earnings by $220 million. All other items decreased earnings by $710 million, reflecting about $680 million in unfavorable foreign exchange effects and $220 million in negative tax and inventory impacts, partly offset by asset management gains. Prime product sales of 24.7 million metric tons were up 478,000 metric tons from 2014. U.S. Chemical earnings were $2,386 million, down $418 million from 2014. Non U.S. Chemical earnings were $2,032 million, $521 million higher than the prior year.

2014

Chemical earnings of $4,315 million increased $487 million from 2013. Higher commodity driven margins increased earnings by $520 million, while volume and mix effects increased earnings by $100 million. All other items, primarily higher planned expenses, decreased earnings by $130 million. Prime product sales of 24.2 million metric tons were up 172,000 metric tons from 2013, driven by increased Singapore production. U.S. Chemical earnings were $2,804 million, up $49 million from 2013. Non U.S. Chemical earnings were $1,511 million, $438 million higher than the prior year.

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

Corporate and Financing

	2015	2014	2013
		(millions of dollars)	
Corporate and financing	(1,926)	(2,388)	(1,538)

2015

Corporate and financing expenses were $1,926 million in 2015 compared to $2,388 million in 2014, with the decrease due mainly to net favorable tax related items.

2014

Corporate and financing expenses were $2,388 million in 2014, up $850 million from 2013 due primarily to tax related items.

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2015	2014	2013
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	30,344	45,116	44,914
Investing activities	(23,824)	(26,975)	(34,201)
Financing activities	(7,037)	(17,888)	(15,476)
Effect of exchange rate changes	(394)	(281)	(175)
Increase/(decrease) in cash and cash equivalents	(911)	(28)	(4,938)
		(December 31)	
Cash and cash equivalents	3,705	4,616	4,644
Cash and cash equivalents - restricted	-	42	269
Total cash and cash equivalents	3,705	4,658	4,913

Total cash and cash equivalents were $3.7 billion at the end of 2015, $1.0 billion lower than the prior year. The major sources of funds in 2015 were net income including noncontrolling interests of $16.6 billion, the adjustment for the noncash provision of $18.0 billion for depreciation and depletion, and a net debt increase of $9.3 billion. The major uses of funds included spending for additions to property, plant and equipment of $26.5 billion, the purchase of shares of ExxonMobil stock of $4.0 billion, dividends to shareholders of $12.1 billion and a change in working capital, excluding cash and debt, of $3.1 billion.

Total cash and cash equivalents were $4.7 billion at the end of 2014, $0.3 billion lower than the prior year. The major sources of funds in 2014 were net income including noncontrolling interests of $33.6 billion, the adjustment for the noncash provision of $17.3 billion for depreciation and depletion, a net debt increase of $7.0 billion and collection of advances of $3.3 billion. The major uses of funds included spending for additions to property, plant and equipment of $33.0 billion, the purchase of shares of ExxonMobil stock of $13.2 billion, dividends to shareholders of $11.6 billion and a change in working capital, excluding cash and debt, of $4.9 billion. Included in total cash and cash equivalents at year-end 2014 was $42 million 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, supplemented by long-term and short-term debt. On December 31, 2015, the Corporation had unused committed short-term lines of credit of $6.0 billion and unused committed long-term lines of credit of $0.4 billion. 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 the impact of fiscal and commercial terms.

The Corporation has long been successful at offsetting the effects of natural field decline through disciplined investments in quality opportunities and project execution. On average over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; and changes in the amount and timing of investments that may vary depending on the oil and gas price environment. 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.

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The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2015 were $31.1 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment level of $23.2 billion in 2016. The Corporation is emerging from several years of high capital expenditure levels that supported major long-plateau production projects coming on line. Lower levels of capital spending over the next few years, partly due to cost savings and capital efficiencies, are not expected to delay major project schedules nor have a material effect on our volume capacity outlook.

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 Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments.

Cash Flow from Operating Activities

2015

Cash provided by operating activities totaled $30.3 billion in 2015, $14.8 billion lower than 2014. The major source of funds was net income including noncontrolling interests of $16.6 billion, a decrease of $17.1 billion. The noncash provision for depreciation and depletion was $18.0 billion, up $0.8 billion from the prior year. The adjustment for net gains on asset sales was $0.2 billion compared to an adjustment of $3.2 billion in 2014. Changes in operational working capital, excluding cash and debt, decreased cash in 2015 by $3.1 billion.

2014

Cash provided by operating activities totaled $45.1 billion in 2014, $0.2 billion higher than 2013. The major source of funds was net income including noncontrolling interests of $33.6 billion, an increase of $0.2 billion. The noncash provision for depreciation and depletion was $17.3 billion, up $0.1 billion from the prior year. The adjustment for net gains on asset sales was $3.2 billion compared to an adjustment of $1.8 billion in 2013. Changes in operational working capital, excluding cash and debt, decreased cash in 2014 by $4.9 billion.

Cash Flow from Investing Activities

2015

Cash used in investment activities netted to $23.8 billion in 2015, $3.2 billion lower than 2014. Spending for property, plant and equipment of $26.5 billion decreased $6.5 billion from 2014. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $2.4 billion compared to $4.0 billion in 2014. Additional investments and advances were $1.0 billion lower in 2015, while collection of advances was $2.5 billion lower in 2015.

2014

Cash used in investment activities netted to $27.0 billion in 2014, $7.2 billion lower than 2013. Spending for property, plant and equipment of $33.0 billion decreased $0.7 billion from 2013. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $4.0 billion compared to $2.7 billion in 2013. Additional investments and advances were $2.8 billion lower in 2014, while collection of advances was $2.2 billion higher in 2014.

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

Cash Flow from Financing Activities

2015

Cash used in financing activities was $7.0 billion in 2015, $10.9 billion lower than 2014. Dividend payments on common shares increased to $2.88 per share from $2.70 per share and totaled $12.1 billion, a pay-out of 75 percent of net income. During the first quarter of 2015, the Corporation issued $8.0 billion of long-term debt. Total debt increased $9.6 billion to $38.7 billion at year end.

ExxonMobil share of equity decreased $3.6 billion to $170.8 billion. The addition to equity for earnings was $16.2 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $15.1 billion, composed of $12.1 billion in dividends and $3.0 billion of share purchases of ExxonMobil stock to reduce shares outstanding. Foreign exchange translation effects of $8.2 billion for the stronger U.S. currency reduced equity, while a $3.6 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2015, Exxon Mobil Corporation purchased 48 million shares of its common stock for the treasury at a gross cost of $4.0 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 1.1 percent from 4,201 million to 4,156 million at the end of 2015. 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.

2014

Cash used in financing activities was $17.9 billion in 2014, $2.4 billion higher than 2013. Dividend payments on common shares increased to $2.70 per share from $2.46 per share and totaled $11.6 billion, a pay-out of 36 percent of net income. During the first quarter of 2014, the Corporation issued $5.5 billion of long-term debt. Total debt increased $6.4 billion to $29.1 billion at year end.

ExxonMobil share of equity increased $0.4 billion to $174.4 billion. The addition to equity for earnings was $32.5 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $23.6 billion, composed of $11.6 billion in dividends and $12.0 billion of share purchases of ExxonMobil stock to reduce shares outstanding. Foreign exchange translation effects of $5.1 billion for the stronger U.S. currency and a $3.1 billion change in the funded status of the postretirement benefits reserves also reduced equity.

During 2014, Exxon Mobil Corporation purchased 136 million shares of its common stock for the treasury at a gross cost of $13.2 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 3.1 percent from 4,335 million to 4,201 million at the end of 2014. 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, 2015. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period			
Commitments	**Note Reference Number**	**2016**	**2017-2020**	**2021 and Beyond**	**Total**
		(millions of dollars)			
Long-term debt *(1)*	14	-	9,902	10,023	19,925
– Due in one year *(2)*	6	558	-	-	558
Asset retirement obligations *(3)*	9	871	3,760	9,073	13,704
Pension and other postretirement obligations *(4)*	17	3,495	4,104	15,567	23,166
Operating leases *(5)*	11	1,653	2,167	1,057	4,877
Unconditional purchase obligations *(6)*	16	133	493	310	936
Take-or-pay obligations *(7)*		2,997	9,463	12,410	24,870
Firm capital commitments *(8)*		10,320	4,438	441	15,199

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 $9.4 billion as of December 31, 2015, 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 $1,238 million.

(2) The amount due in one year is included in notes and loans payable of $18,762 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 2016 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. Total includes $1,621 million related to drilling rigs and related equipment.

(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 $936 million mainly pertain to pipeline throughput agreements and include $411 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 $24,870 million mainly pertain to pipeline, manufacturing supply and terminal agreements.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $15.2 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $8.0 billion was associated with projects in Africa, United Arab Emirates, Canada, Malaysia, Kazakhstan and Australia. The Corporation expects to fund the majority of these projects with internally generated funds, supplemented by long-term and short-term debt.

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, 2015, 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, 2015, the Corporation's unused short-term committed lines of credit totaled approximately $6.0 billion (Note 6) and unused long-term committed lines of credit totaled approximately $0.4 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.

	2015	**2014**	**2013**
Fixed-charge coverage ratio (times)	17.6	46.9	55.7
Debt to capital (percent)	18.0	13.9	11.2
Net debt to capital (percent)	16.5	11.9	9.1

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

		2015			**2014**	
	U.S.	**Non-U.S.**	**Total**	**U.S.**	**Non-U.S.**	**Total**
			(millions of dollars)			
Upstream *(1)*	7,822	17,585	25,407	9,401	23,326	32,727
Downstream	1,039	1,574	2,613	1,310	1,724	3,034
Chemical	1,945	898	2,843	1,690	1,051	2,741
Other	188	-	188	35	-	35
Total	10,994	20,057	31,051	12,436	26,101	38,537

(1) Exploration expenses included.

Capital and exploration expenditures in 2015 were $31.1 billion, 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 investment level of $23.2 billion in 2016. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $25.4 billion in 2015 was down 22 percent from 2014, reflecting key project start-ups and capital efficiencies. Investments in 2015 included projects in the U.S. Gulf of Mexico and Alaska, U.S. onshore drilling and continued progress on world-class projects in Canada and Australia. 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. The percentage of proved developed reserves was 73 percent of total proved reserves at year-end 2015, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled $2.6 billion in 2015, a decrease of $0.4 billion from 2014, mainly reflecting lower refining project spending. The Chemical capital expenditures of $2.8 billion increased $0.1 billion from 2014 with higher investments in the U.S.

TAXES

	2015	**2014**	**2013**
		(millions of dollars)	
Income taxes	5,415	18,015	24,263
Effective income tax rate	*34%*	*41%*	*48%*
Sales-based taxes	22,678	29,342	30,589
All other taxes and duties	29,790	35,515	36,396
Total	57,883	82,872	91,248

2015

Income, sales-based and all other taxes and duties totaled $57.9 billion in 2015, a decrease of $25.0 billion or 30 percent from 2014. Income tax expense, both current and deferred, was $5.4 billion, $12.6 billion lower than 2014, as a result of lower earnings and a lower effective tax rate. The effective tax rate was 34 percent compared to 41 percent in the prior year due primarily to a lower share of earnings in higher tax jurisdictions. Sales-based and all other taxes and duties of $52.5 billion in 2015 decreased $12.4 billion as a result of lower sales realizations.

2014

Income, sales-based and all other taxes and duties totaled $82.9 billion in 2014, a decrease of $8.4 billion or 9 percent from 2013. Income tax expense, both current and deferred, was $18.0 billion, $6.2 billion lower than 2013, as a result of a lower effective tax rate. The effective tax rate was 41 percent compared to 48 percent in the prior year due primarily to impacts related to the Corporation's asset management program and favorable U.S. deferred tax items. Sales-based and all other taxes and duties of $64.9 billion in 2014 decreased $2.1 billion.

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

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2015	2014
	(millions of dollars)	
Capital expenditures	1,869	2,666
Other expenditures	3,777	3,522
Total	5,646	6,188

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 2015 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $5.6 billion, of which $3.8 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to decrease to approximately $5 billion in 2016 and 2017, mainly reflecting lower project activity in Canada. Capital expenditures are expected to account for approximately 30 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 2015 for environmental liabilities were $371 million ($780 million in 2014) and the balance sheet reflects accumulated liabilities of $837 million as of December 31, 2015, and $1,066 million as of December 31, 2014.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	**2015**	**2014**	**2013**

Crude oil and NGL ($/barrel)	44.77	87.42	97.48
Natural gas ($/kcf)	2.95	4.68	4.60

(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 $375 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 $150 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 represent Upstream production 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 global economic conditions, political events, decisions by OPEC and other major government resource owners and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the Corporation evaluates the viability of all of its investments over a broad range of prices. The Corporation's assessment is that its operations will continue to be successful over the long term 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, supplemented by long-term and short-term debt. 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. Beginning several years ago, an extended period of increased demand for certain services and materials resulted in higher operating and capital costs. More recently, multiple market changes, including general commodity price decreases, lower oil prices and reduced upstream industry activity, have contributed to lower prices for oilfield services and materials. The Corporation works to minimize costs in all commodity price environments 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

RECENTLY ISSUED ACCOUNTING STANDARDS

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2018.

"Sales and Other Operating Revenue" on the Consolidated Statement of Income includes sales, excise and value-added taxes on sales transactions. When the Corporation adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings.

The Corporation continues to evaluate other areas of the standard and its effect on the Corporation's financial statements.

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, together with proved reserves, are as likely as not to be recovered.

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 73 percent of total proved reserves at year-end 2015 (including both consolidated and equity company reserves), and has been over 60 percent for the last ten years.

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.

When crude oil and natural gas prices are in the range seen in late 2015 and early 2016 for an extended period of time, under the SEC definition of proved reserves, certain quantities of oil and natural gas, such as oil sands operations in Canada and natural gas operations in North America could temporarily not qualify as proved reserves. Amounts that could be required to be de-booked as proved reserves on an SEC basis are subject to being re-booked as proved reserves at some point in the future when price levels recover, costs decline, or operating efficiencies occur. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to ExxonMobil. We do not expect any temporary changes in reported proved reserves under SEC definitions to affect the operation of the underlying projects or to alter our outlook for future production volumes.

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

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 reserves or proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), applied to the asset cost. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative such as the straight-line method is used. The volumes produced and asset cost are known and, while proved 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, Prices and Margins on Testing for Impairment. The Corporation performs impairment assessments whenever events or circumstances indicate that the carrying amounts of its long-lived assets (or group of assets) may not be recoverable through future operations or disposition. 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 for this assessment.

Potential trigger events for impairment evaluation include:

- a significant decrease in the market price of a long-lived asset;
- a significant adverse change in the extent or manner in which an asset is being used or in its physical condition including a significant decrease in current and projected reserve volumes;
- a significant adverse change in legal factors or in the business climate that could affect the value, including an adverse action or assessment by a regulator;
- an accumulation of project costs significantly in excess of the amount originally expected;
- a current-period operating loss combined with a history and forecast of operating or cash flow losses; and
- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, the Corporation does not view temporarily low prices or margins as a trigger event for conducting impairment tests. The markets for crude oil, natural gas and petroleum products 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.

If there were a trigger event, 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 estimates for future crude oil and natural gas commodity prices, refining and chemical margins, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. These evaluations make use of the Corporation's price, margin, volume, and cost assumptions developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the 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. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

In light of continued weakness in the upstream industry environment in late 2015, the Corporation undertook an effort to assess its major long-lived assets most at risk for potential impairment. The results of this assessment confirm the absence of a trigger event and indicate that the future undiscounted cash flows associated with these assets substantially exceed the carrying value of the assets. The assessment reflects crude and natural gas prices that are generally consistent with the long-term price forecasts published by third-party industry experts. Critical to the long-term recoverability of certain assets is the assumption that either by supply and demand changes, or due to general inflation, prices will rise in the future. Should increases in long-term prices not materialize, certain of the Corporation's assets will be at risk for impairment. Due to the inherent difficulty in predicting future commodity prices, and the relationship between industry prices and costs, it is not practicable to reasonably estimate a range of potential future impairments related to the Corporation's long-lived assets.

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.

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.

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). If crude oil, natural gas, petroleum product and chemical product prices continue in the range seen in early 2016, the Corporation could be subject to a lower of cost or market inventory valuation adjustment.

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 about 100 defined benefit (pension) plans in over 40 countries. The Pension and Other Postretirement Benefits footnote (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 because tax conventions and regulatory practices do not encourage advance funding. Book reserves are established for these plans. 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 2015 was 7.00 percent. The 10 year and 20 year actual returns on U.S. pension plan assets were 5 percent and 8 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.

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

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 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 (2013)* 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, 2015.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2015, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson	Andrew P. Swiger	David S. Rosenthal
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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 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, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* 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 24, 2016

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2015	2014	2013
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		259,488	394,105	420,836
Income from equity affiliates	7	7,644	13,323	13,927
Other income		1,750	4,511	3,492
Total revenues and other income		268,882	411,939	438,255
Costs and other deductions				
Crude oil and product purchases		130,003	225,972	244,156
Production and manufacturing expenses		35,587	40,859	40,525
Selling, general and administrative expenses		11,501	12,598	12,877
Depreciation and depletion		18,048	17,297	17,182
Exploration expenses, including dry holes		1,523	1,669	1,976
Interest expense		311	286	9
Sales-based taxes *(1)*	19	22,678	29,342	30,589
Other taxes and duties	19	27,265	32,286	33,230
Total costs and other deductions		246,916	360,309	380,544
Income before income taxes		21,966	51,630	57,711
Income taxes	19	5,415	18,015	24,263
Net income including noncontrolling interests		16,551	33,615	33,448
Net income attributable to noncontrolling interests		401	1,095	868
Net income attributable to ExxonMobil		16,150	32,520	32,580
Earnings per common share *(dollars)*	12	3.85	7.60	7.37
Earnings per common share - assuming dilution *(dollars)*	12	3.85	7.60	7.37

(1) Sales and other operating revenue includes sales-based taxes of $22,678 million for 2015, $29,342 million for 2014 and $30,589 million for 2013.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2015	2014	2013
		(millions of dollars)	
Net income including noncontrolling interests	16,551	33,615	33,448
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(9,303)	(5,847)	(3,620)
Adjustment for foreign exchange translation (gain)/loss included in net income	(14)	152	(23)
Postretirement benefits reserves adjustment (excluding amortization)	2,358	(4,262)	3,174
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,448	1,111	1,820
Unrealized change in fair value of stock investments	33	(63)	-
Realized (gain)/loss from stock investments included in net income	27	3	-
Total other comprehensive income	(5,451)	(8,906)	1,351
Comprehensive income including noncontrolling interests	11,100	24,709	34,799
Comprehensive income attributable to noncontrolling interests	(496)	421	760
Comprehensive income attributable to ExxonMobil	11,596	24,288	34,039

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2015	Dec. 31 2014
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		3,705	4,616
Cash and cash equivalents - restricted		-	42
Notes and accounts receivable, less estimated doubtful amounts	6	19,875	28,009
Inventories			
Crude oil, products and merchandise	3	12,037	12,384
Materials and supplies		4,208	4,294
Other current assets		2,798	3,565
Total current assets		42,623	52,910
Investments, advances and long-term receivables	8	34,245	35,239
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	251,605	252,668
Other assets, including intangibles, net		8,285	8,676
Total assets		336,758	349,493
Liabilities			
Current liabilities			
Notes and loans payable	6	18,762	17,468
Accounts payable and accrued liabilities	6	32,412	42,227
Income taxes payable		2,802	4,938
Total current liabilities		53,976	64,633
Long-term debt	14	19,925	11,653
Postretirement benefits reserves	17	22,647	25,802
Deferred income tax liabilities	19	36,818	39,230
Long-term obligations to equity companies		5,417	5,325
Other long-term obligations		21,165	21,786
Total liabilities		159,948	168,429
Commitments and contingencies	16		
Equity			
Common stock without par value			
(9,000 million shares authorized, 8,019 million shares issued)		11,612	10,792
Earnings reinvested		412,444	408,384
Accumulated other comprehensive income		(23,511)	(18,957)
Common stock held in treasury			
(3,863 million shares in 2015 and 3,818 million shares in 2014)		(229,734)	(225,820)
ExxonMobil share of equity		170,811	174,399
Noncontrolling interests		5,999	6,665
Total equity		176,810	181,064

Total liabilities and equity	336,758	349,493

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2015	2014	2013
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		16,551	33,615	33,448
Adjustments for noncash transactions				
Depreciation and depletion		18,048	17,297	17,182
Deferred income tax charges/(credits)		(1,832)	1,540	754
Postretirement benefits expense				
in excess of/(less than) net payments		2,153	524	2,291
Other long-term obligation provisions				
in excess of/(less than) payments		(380)	1,404	(2,566)
Dividends received greater than/(less than) equity in current				
earnings of equity companies		(691)	(358)	3
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		4,692	3,118	(305)
- Inventories		(379)	(1,343)	(1,812)
- Other current assets		45	(68)	(105)
Increase/(reduction) - Accounts and other payables		(7,471)	(6,639)	(2,498)
Net (gain) on asset sales	5	(226)	(3,151)	(1,828)
All other items - net	5	(166)	(823)	350
Net cash provided by operating activities		30,344	45,116	44,914
Cash flows from investing activities				
Additions to property, plant and equipment	5	(26,490)	(32,952)	(33,669)
Proceeds associated with sales of subsidiaries, property, plant				
and equipment, and sales and returns of investments	5	2,389	4,035	2,707
Decrease/(increase) in restricted cash and cash equivalents		42	227	72
Additional investments and advances		(607)	(1,631)	(4,435)
Collection of advances		842	3,346	1,124
Net cash used in investing activities		(23,824)	(26,975)	(34,201)
Cash flows from financing activities				
Additions to long-term debt	5	8,028	5,731	345
Reductions in long-term debt		(26)	(69)	(13)
Additions to short-term debt		-	-	16
Reductions in short-term debt		(506)	(745)	(756)
Additions/(reductions) in commercial paper, and debt with				
three months or less maturity	5	1,759	2,049	12,012
Cash dividends to ExxonMobil shareholders		(12,090)	(11,568)	(10,875)
Cash dividends to noncontrolling interests		(170)	(248)	(304)
Changes in noncontrolling interests		-	-	(1)
Tax benefits related to stock-based awards		2	115	48
Common stock acquired		(4,039)	(13,183)	(15,998)

Common stock sold	5	30	50
Net cash used in financing activities	(7,037)	(17,888)	(15,476)
Effects of exchange rate changes on cash	(394)	(281)	(175)
Increase/(decrease) in cash and cash equivalents	(911)	(28)	(4,938)
Cash and cash equivalents at beginning of year	4,616	4,644	9,582
Cash and cash equivalents at end of year	3,705	4,616	4,644

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						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
	(millions of dollars)						
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
Amortization of stock-based awards	780	-	-	-	780	-	780
Tax benefits related to stock-based awards	49	-	-	-	49	-	49
Other	(114)	-	-	-	(114)	-	(114)
Net income for the year	-	32,520	-	-	32,520	1,095	33,615
Dividends - common shares	-	(11,568)	-	-	(11,568)	(248)	(11,816)
Other comprehensive income	-	-	(8,232)	-	(8,232)	(674)	(8,906)
Acquisitions, at cost	-	-	-	(13,183)	(13,183)	-	(13,183)
Dispositions	-	-	-	144	144	-	144
Balance as of December 31, 2014	10,792	408,384	(18,957)	(225,820)	174,399	6,665	181,064
Amortization of stock-based awards	828	-	-	-	828	-	828
Tax benefits related to stock-based awards	116	-	-	-	116	-	116
Other	(124)	-	-	-	(124)	-	(124)
Net income for the year	-	16,150	-	-	16,150	401	16,551
Dividends - common shares	-	(12,090)	-	-	(12,090)	(170)	(12,260)
	-	-	(4,554)	-	(4,554)	(897)	(5,451)

Other comprehensive income							
Acquisitions, at cost	-	-	-	(4,039)	(4,039)	-	(4,039)
Dispositions	-	-	-	125	125	-	125
Balance as of December 31, 2015	11,612	412,444	(23,511)	(229,734)	170,811	5,999	176,810

Common Stock Share Activity	**Issued**	**Held in Treasury**	**Outstanding**
		(millions of shares)	
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
Acquisitions	-	(136)	(136)
Dispositions	-	2	2
Balance as of December 31, 2014	8,019	(3,818)	4,201
Acquisitions	-	(48)	(48)
Dispositions	-	3	3
Balance as of December 31, 2015	8,019	(3,863)	4,156

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).

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 2015 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, 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.

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. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. Exploratory well costs are carried as an asset 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. Development costs, including costs of productive wells and development dry holes, are capitalized.

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. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative such as the straight-line method is used.

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.

The Corporation performs impairment assessments whenever events or circumstances indicate that the carrying amounts of its long-lived assets (or group of assets) may not be recoverable through future operations or disposition. 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 for this assessment.

Potential trigger events for impairment evaluation include:

- a significant decrease in the market price of a long-lived asset;

- a significant adverse change in the extent or manner in which an asset is being used or in its physical condition including a significant decrease in current and projected reserve volumes;

- a significant adverse change in legal factors or in the business climate that could affect the value, including an adverse action or assessment by a regulator;

- an accumulation of project costs significantly in excess of the amount originally expected;

- a current-period operating loss combined with a history and forecast of operating or cash flow losses; and

- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, the Corporation does not view temporarily low prices or margins as a trigger event for conducting impairment tests. The markets for crude oil, natural gas and petroleum products, 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

If there were a trigger event, 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 estimates for future crude oil and natural gas commodity prices, refining and chemical margins, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. These evaluations make use of the Corporation's price, margin, volume, and cost assumptions developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the 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. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

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.

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.

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.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2015 that had a material impact on the Corporation's financial statements.

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2018.

"Sales and Other Operating Revenue" on the Consolidated Statement of Income includes sales, excise and value-added taxes on sales transactions. When the Corporation adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings.

The Corporation continues to evaluate other areas of the standard and its effect on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,008 million in 2015, $971 million in 2014 and $1,044 million in 2013.

Net income included before tax aggregate foreign exchange transaction losses of $119 million and $225 million in 2015 and 2014, respectively, and gains of $155 million in 2013.

In 2015, 2014 and 2013, net income included a loss of $186 million, and gains of $187 million and $282 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 $4.5 billion and $10.6 billion at December 31, 2015, and 2014, respectively.

Crude oil, products and merchandise as of year-end 2015 and 2014 consist of the following:

	2015	**2014**
	(billions of dollars)	
Crude oil	4.2	4.6
Petroleum products	4.1	4.1
Chemical products	2.7	2.9
Gas/other	1.0	0.8
Total	12.0	12.4

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	**Cumulative Foreign Exchange Translation Adjustment**	**Post-retirement Benefits Reserves Adjustment**	**Unrealized Change in Stock Investments**	**Total**
		(millions of dollars)		
Balance as of December 31, 2012	2,410	(14,594)	-	(12,184)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(3,233)	2,963	-	(270)
Amounts reclassified from accumulated other comprehensive income	(23)	1,752	-	1,729
Total change in accumulated other comprehensive income	(3,256)	4,715	-	1,459
Balance as of December 31, 2013	(846)	(9,879)	-	(10,725)
Balance as of December 31, 2013	(846)	(9,879)	-	(10,725)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(5,258)	(4,132)	(63)	(9,453)
Amounts reclassified from accumulated other comprehensive income	152	1,066	3	1,221
Total change in accumulated other comprehensive income	(5,106)	(3,066)	(60)	(8,232)
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(8,204)	2,202	33	(5,969)
Amounts reclassified from accumulated other comprehensive income	(14)	1,402	27	1,415
Total change in accumulated other comprehensive income	(8,218)	3,604	60	(4,554)
Balance as of December 31, 2015	(14,170)	(9,341)	-	(23,511)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	**2015**	**2014**	**2013**
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	14	(152)	23
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs *(1)*	(2,066)	(1,571)	(2,616)
Realized change in fair value of stock investments included in net income			

(Statement of Income line: Other income)	(42)	(5)	-

(1) These accumulated other comprehensive income components are included in the computation of net periodic pension cost. (See Note 17 – Pension and Other Postretirement Benefits for additional details.)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	**2015**	**2014**	**2013**
	(millions of dollars)		
Foreign exchange translation adjustment	170	292	218
Postretirement benefits reserves adjustment (excluding amortization)	(1,192)	2,009	(1,540)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(618)	(460)	(796)
Unrealized change in fair value of stock investments	(17)	34	-
Realized change in fair value of stock investments included in net income	(15)	(2)	-
Total	(1,672)	1,873	(2,118)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Cash Flow Information

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. Highly liquid investments with maturities of three months or less when acquired are classified as cash equivalents.

For 2015, the “Net (gain) on asset sales” on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of service stations in Europe, the sale of Upstream properties in the U.S., the sale of ExxonMobil’s interests in Chemical and Refining joint ventures, and the pending sale of the Torrance refinery. For 2014, the amount includes before-tax gains from the sale of Hong Kong power operations, additional proceeds related to the 2013 sale of a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale or exchange of Upstream properties in the U.S., Canada, and Malaysia. For 2013, the amount includes before-tax gains from the sale of a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale of service stations. These net gains are reported in “Other income” on the Consolidated Statement of Income.

In 2015, the “Additions/(reductions) in commercial paper, and debt with three months or less maturity” on the Consolidated Statement of Cash Flows includes a net $358 million addition of commercial paper with maturity over three months. The gross amount issued was $8.1 billion, while the gross amount repaid was $7.7 billion.

In 2015, ExxonMobil completed an asset exchange that resulted in value received of approximately $500 million including $100 million in cash. The non-cash portion was not included in the “Sales of subsidiaries, investments, and property, plant and equipment” or the “All other items-net” lines on the Statement of Cash Flows. Capital leases of approximately $1 billion were not included in the “Additions to long-term debt” or “Additions to property, plant and equipment” lines on the Statement of Cash Flows.

In 2014, ExxonMobil completed asset exchanges, primarily non-cash transactions, of approximately $1.2 billion. This amount is not included in the “Sales of subsidiaries, investments, and property, plant and equipment” or the “Additions to property, plant and equipment” lines on the Statement of Cash Flows.

	2015	**2014**	**2013**
		(millions of dollars)	
Cash payments for interest	586	380	426
Cash payments for income taxes	7,269	18,085	25,066

6. Additional Working Capital Information

	Dec. 31 2015	**Dec. 31 2014**
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $107 million and $113 million	13,243	18,541
Other, less reserves of $4 million and $48 million	6,632	9,468
Total	19,875	28,009

Notes and loans payable		
Bank loans	231	473
Commercial paper	17,973	16,225
Long-term debt due within one year	558	770
Total	18,762	17,468
Accounts payable and accrued liabilities		
Trade payables	18,074	25,286
Payables to equity companies	4,639	6,589
Accrued taxes other than income taxes	2,937	3,290
Other	6,762	7,062
Total	32,412	42,227

The Corporation has short-term committed lines of credit of $6.0 billion which were unused as of December 31, 2015. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 0.4 percent and 0.3 percent at December 31, 2015, and 2014, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These companies are primarily engaged in oil and gas exploration and production, and natural gas marketing in North America; natural gas exploration, production and distribution, and downstream operations in Europe; and exploration, production, liquefied natural gas (LNG) operations, refining operations, petrochemical manufacturing, and fuel sales in Asia. Also included are several refining, petrochemical manufacturing, and marketing ventures.

The Corporation's ownership in these ventures is in the form of shares in corporate joint ventures as well as interests in partnerships. Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the factors giving rise to the difference. The amortization of this difference, as appropriate, is included in "income from equity affiliates."

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 15 percent, 14 percent and 13 percent in the years 2015, 2014 and 2013, respectively.

In 2013 and 2014, the Corporation and Rosneft established various entities to conduct exploration and research activities. Periods of disproportionate funding will result in the Corporation recognizing, during the early phases of the projects, an investment that is larger than its equity share in these entities. These joint ventures are considered Variable Interest Entities. However, since the Corporation is not the primary beneficiary of these entities, the joint ventures are reported as equity companies. In 2014, the European Union and United States imposed sanctions relating to the Russian energy sector. With respect to the foregoing, each joint venture continues to comply with all applicable laws, rules and regulations. The Corporation's maximum before-tax exposure to loss from these joint ventures as of December 31, 2015, is $1.0 billion.

	2015		**2014**		**2013**	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	111,866	34,297	183,708	55,855	236,161	68,084
Income before income taxes	36,379	10,670	65,549	19,014	69,454	19,999
Income taxes	11,048	3,019	20,520	5,684	21,618	6,069
Income from equity affiliates	25,331	7,651	45,029	13,330	47,836	13,930
Current assets	32,879	11,244	49,905	16,802	62,398	19,545
Long-term assets	109,684	32,878	110,754	33,619	116,450	35,695
Total assets	142,563	44,122	160,659	50,421	178,848	55,240
Current liabilities	22,947	6,738	37,333	11,472	54,550	15,243
Long-term liabilities	60,388	17,165	66,231	19,470	68,857	20,873
Net assets	59,228	20,219	57,095	19,479	55,441	19,124

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A list of significant equity companies as of December 31, 2015, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	18
Karmorneftegaz Holding SARL	33
Marine Well Containment Company LLC	10
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71
Downstream	
Fujian Refining & Petrochemical Co. Ltd.	25
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Holdings B.V.	50
Infineum Italia s.r.l.	50
Infineum USA L.P.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2015	Dec. 31, 2014
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	20,337	20,017
Advances	9,110	9,818
Total equity company investments and advances	29,447	29,835
Companies carried at cost or less and stock investments carried at fair value	274	526

Long-term receivables and miscellaneous investments at cost or less, net of reserves of $3,040 million and $2,662 million	4,524	4,878
Total	34,245	35,239

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2015 Cost	Net	December 31, 2014 Cost	Net
	(millions of dollars)			
Upstream	347,821	203,822	347,170	205,308
Downstream	50,742	21,330	53,327	22,639
Chemical	32,481	16,247	30,717	14,918
Other	16,293	10,206	15,575	9,803
Total	447,337	251,605	446,789	252,668

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

The Corporation periodically reviews the estimated asset service life of its property, plant and equipment. Effective January 1, 2016, the Corporation revised the estimated asset service life of its investments in process equipment in the Chemical segment to 25 years. This revision will not have a material impact on the Corporation’s financial statements.

Accumulated depreciation and depletion totaled $195,732 million at the end of 2015 and $194,121 million at the end of 2014. Interest capitalized in 2015, 2014 and 2013 was $482 million, $344 million and $309 million, respectively.

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 incurred in the current period were Level 3 fair value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in their present value.

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

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

		2015	2014
		(millions of dollars)	
Beginning balance		13,424	12,988
	Accretion expense and other provisions	775	871
	Reduction due to property sales	(208)	(151)
	Payments made	(928)	(724)
	Liabilities incurred	283	122
	Foreign currency translation	(931)	(908)
	Revisions	1,289	1,226
Ending balance		13,704	13,424

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. Accounting for 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. 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.

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

Change in capitalized suspended exploratory well costs:

	2015	**2014**	**2013**
		(millions of dollars)	
Balance beginning at January 1	3,587	2,707	2,679
Additions pending the determination of proved reserves	847	1,095	293
Charged to expense	(5)	(28)	(52)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(43)	(160)	(107)
Divestments/Other	(14)	(27)	(106)
Ending balance at December 31	4,372	3,587	2,707
Ending balance attributed to equity companies included above	696	645	13

Period end capitalized suspended exploratory well costs:

	2015	**2014**	**2013**
		(millions of dollars)	
Capitalized for a period of one year or less	847	1,095	293
Capitalized for a period of between one and five years	2,386	1,659	1,705
Capitalized for a period of between five and ten years	826	544	470
Capitalized for a period of greater than ten years	313	289	239
Capitalized for a period greater than one year - subtotal	3,525	2,492	2,414
Total	4,372	3,587	2,707

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months, which includes the Rosneft joint venture exploration activity (refer to the relevant portion of Note 7).

	2015	2014	2013
Number of projects with first capitalized well drilled in the preceding 12 months	4	8	8
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	55	53	50
Total	59	61	58

Of the 55 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2015, 18 projects have drilling in the preceding 12 months or exploratory activity either planned in the next two years or subject to sanctions. The remaining 37 projects are those with completed exploratory activity progressing toward development.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below provides additional detail for those 37 projects, which total $1,154 million.

Country/Project	Dec. 31, 2015	Years Wells Drilled	Comment
	(millions of dollars)		
Angola			
- Kaombo Split Hub Phase 2	20	2005 - 2006	Evaluating development plan to tie into planned production facilities.
- Perpetua-Zinia-Acacia	15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned in
Australia			
- East Pilchard	7	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/plan infrastructure.
- SE Longtom	11	2010	Gas field near Tuna development, awaiting capacity in existing/planned inf
- SE Remora	34	2010	Gas field near Marlin development, awaiting capacity in existing/planned in
Canada			
- Horn River	241	2009 - 2012	Evaluating development alternatives to tie into planned infrastructure.
Indonesia			
- Alas Tua West	16	2010	Evaluating development plan to tie into planned production facilities.
- Cepu Gas	29	2008 - 2011	Development activity under way, while continuing commercial discussions government.
- Kedung Keris	11	2011	Evaluating development plan to tie into planned production facilities.
- Natuna	118	1981 - 1983	Development activity under way, while continuing discussions with the gov on contract terms pursuant to executed Heads of Agreement.
Kazakhstan			
- Kairan	53	2004 - 2007	Evaluating commercialization and field development alternatives, while co discussions with the government regarding the development plan.
- Kalamkas	18	2006 - 2009	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Malaysia			
- Bindu	2	1995	Awaiting capacity in existing/planned infrastructure.
Nigeria			
- Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the govern regarding regional hub strategy.
- Bosi	79	2002 - 2006	Development activity under way, while continuing discussions with the gov regarding development plan.
- Bosi Central	16	2006	Development activity under way, while continuing discussions with the gov regarding development plan.
- Erha Northeast	26	2008	Evaluating development plan for tieback to existing production facilities.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Satellite Field Development Phase 2	12	2013	Evaluating development plan to tie into planned production facilities.
- Other (4 projects)	14	2002	Evaluating and pursuing development of several additional discoveries.
Norway			
- Gamma	13	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Lavrans	15	1995 - 1999	Evaluating development plan, awaiting capacity in existing Kristin producti
- Other (7 projects)	25	2008 - 2014	Evaluating development plans, including potential for tieback to existing pr

			facilities.
Papua New Guinea			
- Juha	28	2007	Progressing development plans to tie into existing LNG facilities.
Republic of Congo			
- Mer Tres Profonde Sud	56	2000 - 2007	Evaluating development alternatives, while continuing discussions with the regarding development plan.
United Kingdom			
- Phyllis	8	2004	Evaluating development plan for tieback to existing production facilities.
United States			
- Hadrian North	209	2010 - 2013	Evaluating development plan to tie into existing production facilities.
- Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Total 2015 (37 projects)	1,154		

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Leased Facilities

At December 31, 2015, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $4,877 million as indicated in the table. Estimated related rental income from noncancelable subleases is $32 million.

	Lease Payments Under Minimum Commitments			Related
	Drilling Rigs and Related Equipment	Other	Total	Sublease Rental Income
		(millions of dollars)		
2016	827	826	1,653	7
2017	408	595	1,003	6
2018	134	421	555	2
2019	89	255	344	2
2020	77	188	265	2
2021 and beyond	86	971	1,057	13
Total	1,621	3,256	4,877	32

Net rental cost under both cancelable and noncancelable operating leases incurred during 2015, 2014 and 2013 were as follows:

	2015	2014	2013
		(millions of dollars)	
Rental cost			
Drilling rigs and related equipment	1,853	1,763	1,424
Other	2,120	2,314	2,417
Total	3,973	4,077	3,841
Less sublease rental income	44	52	44
Net rental cost	3,929	4,025	3,797

12. Earnings Per Share

	2015	2014	2013

Earnings per common share

Net income attributable to ExxonMobil *(millions of dollars)*	16,150	32,520	32,580
Weighted average number of common shares outstanding *(millions of shares)*	4,196	4,282	4,419
Earnings per common share *(dollars) (1)*	3.85	7.60	7.37
Dividends paid per common share *(dollars)*	2.88	2.70	2.46

(1) The earnings per common share and earnings per common share - assuming dilution are the same in each period shown.

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techniques as appropriate. The only category of financial instruments where the difference between fair value and recorded book value is notable is long-term debt. The estimated fair value of total long-term debt, excluding capitalized lease obligations, was $18.9 billion and $11.7 billion at December 31, 2015, and 2014, respectively, as compared to recorded book values of $18.7 billion and $11.3 billion at December 31, 2015, and 2014, respectively. The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $8.0 billion of long-term debt in the first quarter of 2015.

The fair value of long-term debt by hierarchy level at December 31, 2015, is: Level 1 $18,584 million; Level 2 $208 million; and Level 3 $62 million.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivatives to mitigate the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. 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 estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net asset of $21 million at year-end 2015 and a net asset of $75 million at year-end 2014. Assets and liabilities associated with derivatives are usually recorded either in "Other current assets" or "Accounts payable and accrued liabilities."

The Corporation's fair value measurement of its derivative instruments use either Level 1 or Level 2 inputs.

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $39 million, $110 million and $(7) million during 2015, 2014 and 2013, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and other operating revenue" or "Crude oil and product purchases."

The Corporation believes there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivative activities described above.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

14. Long-Term Debt

At December 31, 2015, long-term debt consisted of $19,217 million due in U.S. dollars and $708 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $558 million, which matures within one year and is included in current liabilities. The increase in the book value of long-term debt reflects the Corporation's issuance of $8.0 billion of long-term debt in the first quarter of 2015. The amounts of long-term debt, including capitalized lease obligations, maturing in each of the four years after December 31, 2016, in millions of dollars, are: 2017 – $2,959; 2018 – $2,967; 2019 – $2,374; and 2020 – $1,602. At December 31, 2015, the Corporation's unused long-term credit lines were $0.4 billion.

Summarized long-term debt at year-end 2015 and 2014 are shown in the table below:

	2015	**2014**
	(millions of dollars)	
Exxon Mobil Corporation		
0.921% notes due 2017	1,500	1,500
Floating-rate notes due 2017 *(1)*	750	750
Floating-rate notes due 2018 *(2)*	500	-
1.305% notes due 2018	1,600	-
1.819% notes due 2019	1,750	1,750
Floating-rate notes due 2019 *(3)*	500	500
1.912% notes due 2020	1,500	-
2.397% notes due 2022	1,150	-
Floating-rate notes due 2022 *(4)*	500	-
3.176% notes due 2024	1,000	1,000
2.709% notes due 2025	1,750	-
3.567% notes due 2045	1,000	-
XTO Energy Inc. *(5)*		
5.650% senior notes due 2016	-	207
6.250% senior notes due 2017	465	477
5.500% senior notes due 2018	377	383
6.500% senior notes due 2018	463	474
6.100% senior notes due 2036	198	199
6.750% senior notes due 2037	307	309
6.375% senior notes due 2038	235	236
Mobil Producing Nigeria Unlimited *(6)*		
Variable notes due 2016-2019	101	399
Esso (Thailand) Public Company Ltd. *(7)*		
Variable notes due 2016-2020	83	121
Mobil Corporation		
8.625% debentures due 2021	249	249

Industrial revenue bonds due 2017-2051 *(8)*	2,611	2,611
Other U.S. dollar obligations *(9)*	97	104
Other foreign currency obligations	1	9
Capitalized lease obligations *(10)*	1,238	375
Total long-term debt	19,925	11,653

(1) Average effective interest rate of 0.3% in 2015 and 0.3% in 2014.

(2) Average effective interest rate of 0.4% in 2015.

(3) Average effective interest rate of 0.5% in 2015 and 0.4% in 2014.

(4) Average effective interest rate of 0.7% in 2015.

(5) Includes premiums of $179 million in 2015 and $219 million in 2014.

(6) Average effective interest rate of 4.6% in 2015 and 4.5% in 2014.

(7) Average effective interest rate of 2.1% in 2015 and 2.4% in 2014.

(8) Average effective interest rate of 0.02% in 2015 and 0.03% in 2014.

(9) Average effective interest rate of 3.8% in 2015 and 4.2% in 2014.

(10) Average imputed interest rate of 9.2% in 2015 and 7.0% in 2014.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2015, remaining shares available for award under the 2003 Incentive Program were 100 million.

Restricted Stock and Restricted Stock Units. Awards totaling 9,681 thousand, 9,775 thousand, and 9,729 thousand of restricted (nonvested) common stock units were granted in 2015, 2014 and 2013, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2015.

	2015	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	44,439	81.45
2014 award issued in 2015	9,758	95.20
Vested	(9,945)	79.86
Forfeited	(189)	82.26
Issued and outstanding at December 31	44,063	84.85

Value of restricted stock and units	**2015**	**2014**	**2013**
Grant price *(dollars)*	81.27	95.20	94.47
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	727	858	843

Units settled in cash	60	73	76
Total value	787	931	919

As of December 31, 2015, there was $2,222 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.5 years. The compensation cost charged against income for the restricted stock and restricted stock units was $855 million, $831 million and $854 million for 2015, 2014 and 2013, respectively. The income tax benefit recognized in income related to this compensation expense was $78 million, $76 million and $78 million for the same periods, respectively. The fair value of shares and units vested in 2015, 2014 and 2013 was $808 million, $946 million and $1,040 million, respectively. Cash payments of $64 million, $73 million and $67 million for vested restricted stock units settled in cash were made in 2015, 2014 and 2013, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

16. Litigation and Other Contingencies

Litigation. A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Corporation does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our contingency disclosures, "significant" includes material matters as well as other matters which management believes should be disclosed. ExxonMobil will continue to defend itself vigorously in these matters. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a material adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole.

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2015, for guarantees relating to notes, loans and performance under contracts. 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.

		Dec. 31, 2015	
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	98	35	133
Other	2,539	4,553	7,092
Total	2,637	4,588	7,225

(1) ExxonMobil share.

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

		Payments Due by Period		
	2016	**2017-2020**	**2021 and Beyond**	**Total**

		(millions of dollars)		
Unconditional purchase obligations *(1)*	133	493	310	936

(1) Undiscounted obligations of $936 million mainly pertain to pipeline throughput agreements and include $411 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of $144 million, totaled $792 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID). The ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Venezuela Bilateral Investment Treaty. On October 9, 2014, the ICSID Tribunal issued its final award finding in favor of the ExxonMobil affiliates and awarding $1.6 billion as of the date of expropriation, June 27, 2007, and interest from that date at 3.25% compounded annually until the date of payment in full. The Tribunal also noted that one of the Cerro Negro Project agreements provides a mechanism to prevent double recovery between the ICSID award and all or part of an earlier award of $908 million to an ExxonMobil affiliate, Mobil Cerro Negro, Ltd., against PdVSA and a PdVSA affiliate, PdVSA CN, in an arbitration under the rules of the International Chamber of Commerce.

On June 12, 2015, the Tribunal rejected in its entirety Venezuela's October 23, 2014, application to revise the ICSID award. The Tribunal also lifted the associated stay of enforcement that had been entered upon the filing of the application to revise.

Still pending is Venezuela's February 2, 2015, application to ICSID seeking annulment of the ICSID award. That application alleges that, in issuing the ICSID award, the Tribunal exceeded its powers, failed to state reasons on which the ICSID award was based, and departed from a fundamental rule of procedure. A separate stay of the ICSID award was entered following the filing of the annulment application. On July 7, 2015, the ICSID Committee considering the annulment application heard arguments from the parties on whether to lift the stay of the award associated with that application. On July 28, 2015, the Committee issued an order that would lift the stay of enforcement unless, within 30 days, Venezuela delivered a commitment to pay the award if the application to annul is denied. On September 17, 2015, the Committee ruled that Venezuela had complied with the requirement to submit a written commitment to pay the award and so left the stay of enforcement in place. A hearing on Venezuela's application for annulment, previously scheduled for January 25-27, 2016, has been rescheduled for March 8-9, 2016.

The United States District Court for the Southern District of New York entered judgment on the ICSID award on October 10, 2014. Motions filed by Venezuela to vacate that judgment on procedural grounds and to modify the judgment by reducing the rate of interest to be paid on the ICSID award from the entry of the court's judgment, until the date of payment, were denied on February 13, 2015, and March 4, 2015, respectively. On March 9, 2015, Venezuela filed a notice of appeal of the court's actions on the two motions. Oral arguments on this appeal were held before the United States Court of Appeals for the Second Circuit on January 7, 2016.

The District Court's judgment on the ICSID award is currently stayed until such time as ICSID's stay of the award entered following Venezuela's filing of its application to annul has been lifted. The net impact of these matters on the Corporation's consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and owns a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in all material respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion plus $234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the award set aside. On May 22, 2012, the court set aside the award. The Contractors appealed that judgment to the Court of Appeal, Abuja Judicial Division. In June 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts if necessary. In October 2014, the Contractors filed suit in the United States District Court for the Southern District of New York to enforce, if necessary, the arbitration award against NNPC assets residing within that jurisdiction. NNPC has moved to dismiss the lawsuit. Proceedings in the Southern District of New York are currently stayed. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless of the outcome of enforcement proceedings, the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2015	2014	2015	2014	2015	2014
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.25	4.00	3.60	3.10	4.25	4.00
Long-term rate of compensation increase	5.75	5.75	4.80	5.30	5.75	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	20,529	17,304	30,047	27,357	9,436	7,868
Service cost	864	677	689	590	170	140
Interest cost	785	807	850	1,138	346	383
Actuarial loss/(gain)	(545)	3,192	(1,517)	4,929	(617)	1,522
Benefits paid *(1) (2)*	(2,050)	(1,427)	(1,287)	(1,366)	(482)	(525)
Foreign exchange rate changes	-	-	(3,242)	(2,540)	(106)	(48)
Amendments, divestments and other	-	(24)	(423)	(61)	(465)	96
Benefit obligation at December 31	19,583	20,529	25,117	30,047	8,282	9,436
Accumulated benefit obligation at December 31	15,666	16,385	22,362	26,318	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2015 and 2014, other postretirement benefits paid are net of $15 million and $21 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the discount rate determined by use of a yield curve based on high-quality, noncallable bonds with cash flows that match estimated outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using bond portfolios with an average maturity approximating that of the liabilities or spot yield curves, both of which are constructed using high-quality, local-currency-denominated bonds.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2017 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $88 million and the postretirement benefit obligation by $963 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $66 million and the postretirement benefit obligation by $764 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2015	**2014**	**2015**	**2014**	**2015**	**2014**
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	12,915	11,190	20,095	19,283	468	620
Actual return on plan assets	(307)	1,497	918	3,153	-	41
Foreign exchange rate changes	-	-	(2,109)	(1,738)	-	-
Company contribution	-	1,476	515	554	42	31
Benefits paid *(1)*	(1,623)	(1,248)	(890)	(912)	(96)	(224)
Other	-	-	(112)	(245)	-	-
Fair value at December 31	10,985	12,915	18,417	20,095	414	468

(1) Benefit payments for funded plans.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The funding levels of all qualified pension plans are in compliance with standards set by applicable law or regulation. As shown in the table below, certain smaller U.S. pension plans and a number of non-U.S. pension plans are not funded because local tax conventions and regulatory practices do not encourage funding of these plans. All defined benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

	Pension Benefits			
	U.S.		Non-U.S.	
	2015	2014	2015	2014
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(5,782)	(4,590)	(588)	(2,113)
Unfunded plans	(2,816)	(3,024)	(6,112)	(7,839)
Total	(8,598)	(7,614)	(6,700)	(9,952)

The authoritative guidance for defined benefit pension and other postretirement plans requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2015	2014	2015	2014	2015	2014
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(8,598)	(7,614)	(6,700)	(9,952)	(7,868)	(8,968)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	-	-	454	302	-	-
Current liabilities	(311)	(340)	(299)	(325)	(363)	(369)
Postretirement benefits reserves	(8,287)	(7,274)	(6,855)	(9,929)	(7,505)	(8,599)
Total recorded	(8,598)	(7,614)	(6,700)	(9,952)	(7,868)	(8,968)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	6,138	6,589	6,413	9,642	2,171	2,997
Prior service cost	21	27	(83)	429	(460)	51
Total recorded in accumulated other						

comprehensive income	6,159	6,616	6,330	10,071	1,711	3,048

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The long-term expected rate of return on funded assets shown below is established for each benefit plan by developing a forward-looking, long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class.

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2015	**2014**	**2013**	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31				*(percent)*					
Discount rate	4.00	5.00	4.00	3.10	4.30	3.80	4.00	5.00	4.00
Long-term rate of return on funded assets	7.00	7.25	7.25	5.90	6.30	6.40	7.00	7.25	7.25
Long-term rate of compensation increase	5.75	5.75	5.75	5.30	5.40	5.50	5.75	5.75	5.75
Components of net periodic benefit cost				*(millions of dollars)*					
Service cost	864	677	801	689	590	697	170	140	176
Interest cost	785	807	749	850	1,138	1,076	346	383	352
Expected return on plan assets	(830)	(799)	(835)	(1,094)	(1,193)	(1,128)	(28)	(37)	(41)
Amortization of actuarial loss/(gain)	544	409	646	730	628	852	206	116	228
Amortization of prior service cost	6	8	7	87	120	117	(24)	14	21
Net pension enhancement and curtailment/settlement cost	499	276	723	22	-	22	-	-	-
Net periodic benefit cost	1,868	1,378	2,091	1,284	1,283	1,636	670	616	736

Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	592	2,494	(1,302)	(1,375)	2,969	(1,938)	(589)	1,518	(1,290)
	(1,043)	(685)	(1,369)	(752)	(628)	(874)	(206)	(116)	(228)

Amortization of actuarial (loss)/gain									
Prior service cost/(credit)	-	(25)	-	(401)	(70)	30	(535)	-	-
Amortization of prior service (cost)/credit	(6)	(8)	(7)	(87)	(120)	(117)	24	(14)	(21)
Foreign exchange rate changes	-	-	-	(1,126)	(688)	(155)	(31)	(8)	(10)
Total recorded in other comprehensive income	(457)	1,776	(2,678)	(3,741)	1,463	(3,054)	(1,337)	1,380	(1,549)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	1,411	3,154	(587)	(2,457)	2,746	(1,418)	(667)	1,996	(813)

Costs for defined contribution plans were $405 million, $393 million and $392 million in 2015, 2014 and 2013, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Total Pension and Other Postretirement Benefits		
	2015	**2014**	**2013**
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	457	(1,776)	2,678
Non-U.S. pension	3,741	(1,463)	3,054
Other postretirement benefits	1,337	(1,380)	1,549
Total (charge)/credit to other comprehensive income, before tax	5,535	(4,619)	7,281
(Charge)/credit to income tax (see Note 4)	(1,810)	1,549	(2,336)
(Charge)/credit to investment in equity companies	81	(81)	49
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	3,806	(3,151)	4,994
Charge/(credit) to equity of noncontrolling interests	(202)	85	(279)
(Charge)/credit to other comprehensive income attributable to ExxonMobil	3,604	(3,066)	4,715

The Corporation's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the portfolio. The benefit plan assets are primarily invested in passive equity and fixed income index funds to diversify risk while minimizing costs. The equity funds hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. The fixed income funds are largely invested in high-quality corporate and government debt securities.

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. benefit plans and the major non-U.S. plans is 40 percent equity securities and 60 percent debt securities. The equity targets for the U.S. and non-U.S. plans include an allocation to private equity partnerships that primarily focus on early-stage venture capital of 5 percent and 3 percent, respectively.

The fair value measurement levels are accounting terms that refer to different methods of valuing assets. The terms do not represent the relative risk or credit quality of an investment.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2015 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension Fair Value Measurement at December 31, 2015, Using:				**Non-U.S. Pension Fair Value Measurement at December 31, 2015, Using:**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	1,992 *(1)*	-	1,992	-	3,179 *(1)*	-	3,179
Non-U.S.	-	1,775 *(1)*	-	1,775	179 *(2)*	3,429 *(1)*	-	3,608
Private equity	-	-	595 *(3)*	595	-	-	581 *(3)*	581
Debt securities								
Corporate	-	4,161 *(4)*	-	4,161	-	2,561 *(4)*	-	2,561
Government	-	2,394 *(4)*	-	2,394	243 *(5)*	8,125 *(4)*	-	8,368
Asset-backed	-	3 *(4)*	-	3	-	71 *(4)*	-	71
Real estate funds	-	-	-	-	-	-	-	-
Cash	-	50 *(6)*	-	50	11	12 *(7)*	-	23
Total at fair value	-	10,375	595	10,970	433	17,377	581	18,391
Insurance contracts								
at contract value				15				26
Total plan assets				10,985				18,417

(1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(2) For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

(3) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(4) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(5) For corporate and government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.

(6) For cash balances held in the form of short-term fund units that are redeemable at the measurement date, the fair value is treated as a Level 2 input.

(7) For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Other Postretirement Fair Value Measurement at December 31, 2015, Using:			
	Level 1	**Level 2**	**Level 3**	**Total**
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	96 *(1)*	-	96
Non-U.S.	-	67 *(1)*	-	67
Private equity	-	-	-	-
Debt securities				
Corporate	-	79 *(2)*	-	79
Government	-	170 *(2)*	-	170
Asset-backed	-	1 *(2)*	-	1
Cash	-	1	-	1
Total at fair value	-	414	-	414

(1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(2) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

The change in the fair value in 2015 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2015			
	Pension			**Other**
	U.S.	**Non-U.S.**		**Postretirement**
	Private Equity	**Private Equity**	**Real Estate**	**Private Equity**
	(millions of dollars)			
Fair value at January 1	562	535	57	2
Net realized gains/(losses)	1	26	(5)	-
Net unrealized gains/(losses)	106	64	-	-
Net purchases/(sales)	(74)	(44)	(52)	(2)
Fair value at December 31	595	581	-	-

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2014 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension Fair Value Measurement at December 31, 2014, Using:				**Non-U.S. Pension Fair Value Measurement at December 31, 2014, Using:**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	2,331 *(1)*	-	2,331	-	3,284 *(1)*	-	3,284
Non-U.S.	-	2,144 *(1)*	-	2,144	229 *(2)*	3,776 *(1)*	-	4,005
Private equity	-	-	562 *(3)*	562	-	-	535 *(3)*	535
Debt securities								
Corporate	-	4,841 *(4)*	-	4,841	-	2,686 *(4)*	-	2,686
Government	-	2,890 *(4)*	-	2,890	249 *(5)*	9,050 *(4)*	-	9,299
Asset-backed	-	5 *(4)*	-	5	-	146 *(4)*	-	146
Real estate funds	-	-	-	-	-	-	57 *(6)*	57
Cash	-	131 *(7)*	-	131	25	31 *(8)*	-	56
Total at fair value	-	12,342	562	12,904	503	18,973	592	20,068
Insurance contracts								
at contract value				11				27
Total plan assets				12,915				20,095

(1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(2) For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

(3) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(4) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(5) For corporate and government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.

(6) For real estate funds, fair value is based on appraised values developed using comparable market transactions.

(7) For cash balances held in the form of short-term fund units that are redeemable at the measurement date, the fair value is treated as a Level 2 input.

(8) For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Other Postretirement Fair Value Measurement at December 31, 2014, Using:			
	Level 1	Level 2	Level 3	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	106 *(1)*	-	106
Non-U.S.	-	75 *(1)*	-	75
Private equity	-	-	2 *(2)*	2
Debt securities				
Corporate	-	103 *(3)*	-	103
Government	-	171 *(3)*	-	171
Asset-backed	-	9 *(3)*	-	9
Cash	-	2	-	2
Total at fair value	-	466	2	468

(1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(2) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(3) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

The change in the fair value in 2014 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2014			
	Pension			Other Postretirement
	U.S.	Non-U.S.		
	Private Equity	Private Equity	Real Estate	Private Equity
	(millions of dollars)			
Fair value at January 1	523	502	136	9
Net realized gains/(losses)	2	23	(17)	-
Net unrealized gains/(losses)	89	31	8	-
Net purchases/(sales)	(52)	(21)	(70)	(7)
Fair value at December 31	562	535	57	2

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2015	2014	2015	2014
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	16,767	17,505	1,827	5,031
Accumulated benefit obligation	13,913	14,493	1,373	4,590
Fair value of plan assets	10,985	12,915	1,299	3,890
For unfunded pension plans:				
Projected benefit obligation	2,816	3,024	6,112	7,839
Accumulated benefit obligation	1,753	1,892	5,290	6,573

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2016 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	930	543	152
Prior service cost *(2)*	6	55	(30)

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

(2) The Corporation amortizes prior service cost on a straight-line basis as permitted under authoritative guidance for defined benefit pension and other postretirement benefit plans.

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2016	2,000			