2014

Financial Statements and Supplemental Information

For the Fiscal Year Ended December 31, 2014

FINANCIAL SECTION

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Financial	Earnings After Income Taxes 2014	2013	Average Capital Employed 2014	2013	Return on Average Capital Employed 2014	2013	Capital and Exploration Expenditures 2014	2013
	(millions of dollars)				(percent)		(millions of dollars)	
Upstream								
United States	5,197	4,191	62,403	59,898	8.3	7.0	9,401	9,145
Non-U.S.	22,351	22,650	102,562	93,071	21.8	24.3	23,326	29,086
Total	27,548	26,841	164,965	152,969	16.7	17.5	32,727	38,231
Downstream								
United States	1,618	2,199	6,070	4,757	26.7	46.2	1,310	951
Non-U.S.	1,427	1,250	17,907	19,673	8.0	6.4	1,724	1,462
Total	3,045	3,449	23,977	24,430	12.7	14.1	3,034	2,413
Chemical								
United States	2,804	2,755	6,121	4,872	45.8	56.5	1,690	963
Non-U.S.	1,511	1,073	16,076	15,793	9.4	6.8	1,051	869
Total	4,315	3,828	22,197	20,665	19.4	18.5	2,741	1,832
Corporate and financing	(2,388)	(1,538)	(8,029)	(6,489)	-	-	35	13
Total	32,520	32,580	203,110	191,575	16.2	17.2	38,537	42,489

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

Operating	2014	2013
	(thousands of barrels daily)	
Net liquids production		
United States	454	431
Non-U.S.	1,657	1,771
Total	2,111	2,202
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	3,404	3,545
Non-U.S.	7,741	8,291
Total	11,145	11,836
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production *(1)*	3,969	4,175

	2014	2013
	(thousands of barrels daily)	
Refinery throughput		
United States	1,809	1,819
Non-U.S.	2,667	2,766
Total	4,476	4,585
	(thousands of barrels daily)	
Petroleum product sales		
United States	2,655	2,609
Non-U.S.	3,220	3,278
Total	5,875	5,887
	(thousands of metric tons)	
Chemical prime product sales *(2)*		
United States	9,528	9,679
Non-U.S.	14,707	14,384
Total	24,235	24,063

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

(2) 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

	2014	2013	2012	2011	2010
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	394,105	420,836	451,509	467,029	370,125
Earnings					
Upstream	27,548	26,841	29,895	34,439	24,097
Downstream	3,045	3,449	13,190	4,459	3,567
Chemical	4,315	3,828	3,898	4,383	4,913
Corporate and financing	(2,388)	(1,538)	(2,103)	(2,221)	(2,117)
Net income attributable to ExxonMobil	32,520	32,580	44,880	41,060	30,460
Earnings per common share	7.60	7.37	9.70	8.43	6.24
Earnings per common share – assuming dilution	7.60	7.37	9.70	8.42	6.22
Cash dividends per common share	2.70	2.46	2.18	1.85	1.74
Earnings to average ExxonMobil share of equity (percent)	18.7	19.2	28.0	27.3	23.7
Working capital	(11,723)	(12,416)	321	(4,542)	(3,649)
Ratio of current assets to current liabilities (times)	0.82	0.83	1.01	0.94	0.94
Additions to property, plant and equipment	34,256	37,741	35,179	33,638	74,156
Property, plant and equipment, less allowances	252,668	243,650	226,949	214,664	199,548
Total assets	349,493	346,808	333,795	331,052	302,510
Exploration expenses, including dry holes	1,669	1,976	1,840	2,081	2,144
Research and development costs	971	1,044	1,042	1,044	1,012
Long-term debt	11,653	6,891	7,928	9,322	12,227
Total debt	29,121	22,699	11,581	17,033	15,014
Fixed-charge coverage ratio (times)	46.9	55.7	62.4	53.4	42.2
Debt to capital (percent)	13.9	11.2	6.3	9.6	9.0
Net debt to capital (percent) *(2)*	11.9	9.1	1.2	2.6	4.5
ExxonMobil share of equity at year-end	174,399	174,003	165,863	154,396	146,839
ExxonMobil share of equity per common share	41.51	40.14	36.84	32.61	29.48
Weighted average number of common shares outstanding (millions)	4,282	4,419	4,628	4,870	4,885
Number of regular employees at year-end (thousands) *(3)*	75.3	75.0	76.9	82.1	83.6
CORS employees not included above (thousands) *(4)*	8.4	9.8	11.1	17.0	20.1

(1) Sales and other operating revenue includes sales-based taxes of $29,342 million for 2014, $30,589 million for 2013, $32,409 million for 2012, $33,503 million for 2011 and $28,547 million for 2010.

(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	**2014**	**2013**	**2012**
		(millions of dollars)	
Net cash provided by operating activities	45,116	44,914	56,170
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	4,035	2,707	7,655
Cash flow from operations and asset sales	49,151	47,621	63,825

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	**2014**	**2013**	**2012**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	349,493	346,808	333,795
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(47,165)	(55,916)	(60,486)
Total long-term liabilities excluding long-term debt	(92,143)	(87,698)	(90,068)
Noncontrolling interests share of assets and liabilities	(9,099)	(8,935)	(6,235)
Add ExxonMobil share of debt-financed equity company net assets	4,766	6,109	5,775
Total capital employed	205,852	200,368	182,781
Total corporate sources: debt and equity perspective			
Notes and loans payable	17,468	15,808	3,653
Long-term debt	11,653	6,891	7,928
ExxonMobil share of equity	174,399	174,003	165,863
Less noncontrolling interests share of total debt	(2,434)	(2,443)	(438)
Add ExxonMobil share of equity company debt	4,766	6,109	5,775
Total capital employed	205,852	200,368	182,781

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	**2014**	**2013**	**2012**
		(millions of dollars)	
Net income attributable to ExxonMobil	32,520	32,580	44,880
Financing costs (after tax)			
Gross third-party debt	(140)	(163)	(401)
ExxonMobil share of equity companies	(256)	(239)	(257)
All other financing costs – net	(68)	83	100
Total financing costs	(464)	(319)	(558)
Earnings excluding financing costs	32,984	32,899	45,438
Average capital employed	203,110	191,575	179,094
Return on average capital employed – corporate total	16.2%	17.2%	25.4%

QUARTERLY INFORMATION

	2014					2013				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
Production of crude oil					*(thousands of barrels daily)*					
and natural gas liquids, synthetic oil and bitumen	2,148	2,048	2,065	2,182	2,111	2,193	2,182	2,199	2,235	2,202
Refinery throughput	4,509	4,454	4,591	4,349	4,476	4,576	4,466	4,847	4,452	4,585
Petroleum product sales	5,817	5,841	5,999	5,845	5,875	5,755	5,765	6,031	5,994	5,887
Natural gas production					*(millions of cubic feet daily)*					
available for sale	12,016	10,750	10,595	11,234	11,145	13,213	11,354	10,914	11,887	11,836
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(1)*	4,151	3,840	3,831	4,054	3,969	4,395	4,074	4,018	4,216	4,175
					(thousands of metric tons)					
Chemical prime product sales	6,128	6,139	6,249	5,719	24,235	5,910	5,831	6,245	6,077	24,063
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(2)(3)*	101,312	105,719	103,206	83,868	394,105	103,378	103,050	108,390	106,018	420,836
Gross profit *(4)*	29,166	28,746	28,825	23,240	109,977	30,083	28,689	30,300	29,901	118,973
Net income attributable to										
ExxonMobil	9,100	8,780	8,070	6,570	32,520	9,500	6,860	7,870	8,350	32,580
Per share data					*(dollars per share)*					
Earnings per common share *(5)*	2.10	2.05	1.89	1.56	7.60	2.12	1.55	1.79	1.91	7.37
Earnings per common share										
– assuming dilution *(5)*	2.10	2.05	1.89	1.56	7.60	2.12	1.55	1.79	1.91	7.37
Dividends per common share	0.63	0.69	0.69	0.69	2.70	0.57	0.63	0.63	0.63	2.46
Common stock prices										
High	101.22	104.61	104.76	97.20	104.76	91.93	93.50	95.49	101.74	101.74
Low	89.25	96.24	93.62	86.19	86.19	86.59	85.02	85.61	84.79	84.79

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

(2) Amounts in first three quarters of 2014 have been reclassified.

(3) Includes amounts for sales-based taxes.

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

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

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

There were 433,941 registered shareholders of ExxonMobil common stock at December 31, 2014. At January 31, 2015, the registered shareholders of ExxonMobil common stock numbered 432,983.

On January 28, 2015, the Corporation declared a $0.69 dividend per common share, payable March 10, 2015.

FUNCTIONAL EARNINGS	2014	2013	2012
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	5,197	4,191	3,925
Non-U.S.	22,351	22,650	25,970
Downstream			
United States	1,618	2,199	3,575
Non-U.S.	1,427	1,250	9,615
Chemical			
United States	2,804	2,755	2,220
Non-U.S.	1,511	1,073	1,678
Corporate and financing	(2,388)	(1,538)	(2,103)
Net income attributable to ExxonMobil (U.S. GAAP)	32,520	32,580	44,880
Earnings per common share	7.60	7.37	9.70
Earnings per common share – assuming dilution	7.60	7.37	9.70

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 results, including demand growth and energy source mix; capacity increases; production growth and mix; rates of field decline; financing sources; the resolution of contingencies and uncertain tax positions; environmental and capital expenditures; could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; the outcome of commercial negotiations; political or regulatory events, and other factors discussed herein and in Item 1A. Risk Factors of ExxonMobil's 2014 Form 10-K.

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

OVERVIEW

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

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new energy supplies. While commodity prices are volatile on a short-term basis and depend on supply and demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products, and chemical products are based on corporate plan assumptions developed annually by major region and are utilized for investment evaluation purposes. Potential investment opportunities are 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.

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

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

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 40 percent from 2010 to 2040. The 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 85 percent by 2040, led by growth in developing countries. Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand is likely to grow most significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today, coal has the largest fuel share in the power sector, but its share is likely to decline significantly by 2040 as policies are gradually adopted to reduce environmental impacts including those related to local air quality and greenhouse gas emissions. Nuclear power and renewables, led by hydropower and wind, are also expected to grow significantly over the period.

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ease of transportation, distribution and storage to meet consumer needs. By 2040, global demand for liquid fuels is expected to grow to approximately 115 million barrels of oil-equivalent per day, an increase of almost 30 percent from 2010. 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 is expected to be the fastest growing major fuel source through 2040. Global demand is expected to rise about 65 percent from 2010 to 2040, with about half 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. About two-thirds of the growth in natural gas supplies is expected to be from unconventional sources, which will account for close to 35 percent of global gas supplies by 2040. The worldwide liquefied natural gas (LNG) market is expected to more than triple by 2040, stimulated by growing natural gas demand.

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 less than 20 percent. Nuclear power is projected to grow significantly, as many nations 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 close to 450 percent from 2010 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 total oil and gas energy needs worldwide over the period 2014-2040 will be about $28 trillion (measured in 2013 dollars) or more than $1 trillion per year on average.

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

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

Upstream

ExxonMobil continues to maintain a diverse portfolio of exploration and development opportunities, which enables the Corporation to be selective, maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies guide our global exploration, development, production, and gas and power marketing activities. These strategies include 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 of ExxonMobil's 2014 Form 10-K, or result in a material change in our level of unit operating expenses.

The Corporation's overall volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the next few years. However, actual volumes will vary from year to year due to the timing of individual project start-ups and other capital activities, operational outages, reservoir performance, performance of enhanced oil recovery projects, regulatory changes, the impact of fiscal and commercial terms, asset sales, weather events, price effects on production sharing contracts and other factors described in Item 1A. Risk Factors of ExxonMobil's 2014 Form 10-K. Enhanced oil recovery projects extract hydrocarbons from reservoirs in excess of that which may be produced through primary recovery, i.e., through pressure depletion or natural aquifer support. They include the injection of water, gases or chemicals into a reservoir to produce hydrocarbons otherwise unobtainable.

The markets for crude oil and natural gas have a history of significant price volatility. After some years of relatively stable prices, the end of 2014 saw crude prices drop to levels not seen since 2009. 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. 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 continue to be successful in a variety of market conditions. This is the outcome of disciplined investment, cost management, and asset enhancement programs.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. The Corporation has a presence in mature markets in North America and Europe, as well as in the growing Asia Pacific region. ExxonMobil's fundamental Downstream business strategies position the company to deliver long-term growth in shareholder value that is superior to competition across a range of market conditions. These strategies include 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 products and services to customers.

ExxonMobil has an ownership interest in 30 refineries, located in 17 countries, with distillation capacity of 5.2 million barrels per day and lubricant basestock manufacturing capacity of 131 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have significant global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes *Exxon*, *Mobil*, *Esso* and *Mobil 1*.

The downstream industry environment remains challenging. Demand weakness and overcapacity in the refining sector will continue to increase competitive pressure. In the near term, we see variability in refining margins, with some regions seeing weaker margins as new capacity additions outpace global demand. In North America, lower raw material and energy cost driven by increasing crude oil and natural gas production has strengthened refining margins over the past few years.

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, in the near term, new capacity additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A. Risk Factors of ExxonMobil's 2014 Form 10-K, proposed carbon policy and other climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could have negative impacts on the refining business. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

In the retail fuels marketing business, competition has caused inflation-adjusted margins to decline. In 2014, ExxonMobil expanded its branded retail site network in the U.S. 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 distributor model. ExxonMobil is increasing investment in its fuels brands and developing multiple programs that will enhance the value of its consumer retail offer. The company's lubricants business continues to grow, leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains a market leader in the high-value synthetic lubricants sector where competition is increasing.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. These investments capitalize on the Corporation's world-class scale and integration, demonstrated efficiency, advanced technology and respected brands, enabling ExxonMobil to take advantage of attractive emerging growth opportunities around the globe. In 2014, the company commissioned the clean fuels project at the joint Saudi Aramco and ExxonMobil SAMREF Refinery in Yanbu, Saudi Arabia, to produce low sulfur gasoline and ultra-low sulfur diesel. Construction started on a new delayed coker unit at the refinery in Antwerp, Belgium, to upgrade low-value bunker fuel into high-value diesel products. The company also completed an expansion of lube basestock capacity at the refinery in Singapore, and neared completion on a lube basestock expansion in Baytown, Texas. A finished lubricant plant expansion in Tianjin, China, was completed and additional lubricant plant expansions in China, Singapore, Finland, and the U.S. are underway to support demand growth for finished lubricants and greases in key markets.

Chemical

Worldwide petrochemical demand continued to improve in 2014, 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 savings. Specialty product margins declined reflecting significant 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 2014, ExxonMobil began construction of 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 meet rapidly growing demand for premium polymers. Construction of new halobutyl rubber and hydrocarbon resin units also started in Singapore to further extend our specialty product capacity in Asia. At the joint venture facility in Al-Jubail, Saudi Arabia, construction continued on the specialty elastomers project that is expected to start-up in 2015.

REVIEW OF 2014 AND 2013 RESULTS

	2014	2013	2012
		(millions of dollars)	
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	32,520	32,580	44,880

Upstream

	2014	2013	2012
		(millions of dollars)	
Upstream			
United States	5,197	4,191	3,925
Non-U.S.	22,351	22,650	25,970
Total	27,548	26,841	29,895

2014

Upstream earnings were $27,548 million, up $707 million from 2013. Lower prices decreased earnings by $2.0 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 4.0 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.

2013

Upstream earnings were $26,841 million, down $3,054 million from 2012. Higher gas realizations, partially offset by lower liquids realizations, increased earnings by $390 million. Production volume and mix effects decreased earnings by $910 million.

All other items, including lower net gains from asset sales, mainly in Angola, and higher expenses, reduced earnings by $2.5 billion. On an oil-equivalent basis, production was down 1.5 percent compared to 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was essentially flat. Liquids production of 2.2 million barrels per day increased 17,000 barrels per day compared with 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was up 1.6 percent, as project ramp-up and lower downtime were partially offset by field decline. Natural gas production of 11.8 billion cubic feet per day decreased 486 million cubic feet per day from 2012. Excluding the impacts of entitlement volumes and divestments, natural gas production was down 1.5 percent, as field decline was partially offset by higher demand, lower downtime, and project ramp-up. Earnings from U.S. Upstream operations for 2013 were $4,191 million, up $266 million from 2012. Earnings outside the U.S. were $22,650 million, down $3,320 million from the prior year.

Upstream Additional Information

	2014	2013
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production)*(1)*		
Prior year	4,175	4,239
Entitlements - Net Interest	(4)	(38)
Entitlements - Price / Spend / Other	(43)	(9)
Quotas	-	3
Divestments	(31)	(26)
United Arab Emirates Onshore Concession Expiry	(135)	-
Growth / Other	7	6
Current Year	3,969	4,175

(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.

Downstream

	2014	2013	2012
		(millions of dollars)	
Downstream			
United States	1,618	2,199	3,575
Non-U.S.	1,427	1,250	9,615
Total	3,045	3,449	13,190

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.

2013

Downstream earnings of $3,449 million decreased $9,741 million from 2012 driven by the absence of the $5.3 billion gain associated with the Japan restructuring. Lower margins, mainly refining, decreased earnings by $2.9 billion. Volume and mix effects decreased earnings by $310 million. All other items, including higher operating expenses, unfavorable foreign exchange impacts, and lower divestments, decreased earnings by $1.2 billion. Petroleum product sales of 5.9 million barrels per day decreased 287,000 barrels per day from 2012. U.S. Downstream earnings were $2,199 million, down $1,376 million from 2012. Non-U.S. Downstream earnings were $1,250 million, a decrease of $8,365 million from the prior year.

Chemical

	2014	2013	2012
		(millions of dollars)	
Chemical			
United States	2,804	2,755	2,220
Non-U.S.	1,511	1,073	1,678
Total	4,315	3,828	3,898

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 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.

2013

Chemical earnings of $3,828 million were $70 million lower than 2012. The absence of the gain associated with the Japan restructuring decreased earnings by $630 million. Higher margins increased earnings by $480 million, while volume and mix effects increased earnings by $80 million. Prime product sales of 24.1 million metric tons were down 94,000 tons from 2012. U.S. Chemical earnings were $2,755 million, up $535 million from 2012. Non-U.S. Chemical earnings were $1,073 million, $605 million lower than the prior year.

Corporate and Financing

	2014	2013	2012
		(millions of dollars)	
Corporate and financing	(2,388)	(1,538)	(2,103)

2014

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

2013

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2014	2013	2012
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	45,116	44,914	56,170
Investing activities	(26,975)	(34,201)	(25,601)
Financing activities	(17,888)	(15,476)	(33,868)
Effect of exchange rate changes	(281)	(175)	217
Increase/(decrease) in cash and cash equivalents	(28)	(4,938)	(3,082)
		(December 31)	
Cash and cash equivalents	4,616	4,644	9,582
Cash and cash equivalents - restricted	42	269	341
Total cash and cash equivalents	4,658	4,913	9,923

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.

Total cash and cash equivalents were $4.9 billion at the end of 2013, $5.0 billion lower than the prior year. The major sources of funds in 2013 were net income including noncontrolling interests of $33.4 billion, the adjustment for the noncash provision of $17.2 billion for depreciation and depletion, and a net debt increase of $11.6 billion. The major uses of funds included spending for additions to property, plant and equipment of $33.7 billion, the purchase of ExxonMobil stock of $16.0 billion, dividends to shareholders of $10.9 billion and a change in working capital, excluding cash and debt, of $4.7 billion. Included in total cash and cash equivalents at year-end 2013 was $0.3 billion of restricted cash. 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, 2014, the Corporation had unused committed short-term lines of credit of $6.3 billion and unused committed long-term lines of credit of $0.5 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. Over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a variety of risks including project start-up timing, operational outages, reservoir performance, the impact of fiscal and commercial terms, crude oil and natural gas prices, weather events, and regulatory changes. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. Risk Factors of ExxonMobil's 2014 Form 10-K for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2014 were $38.5 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an average investment profile of about $34 billion per year for the next few years. Actual spending could vary depending on the progress of individual projects and property acquisitions. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments. The purchase and sale of oil and gas properties have not had a significant impact on the amount or timing of cash flows from operating activities.

Cash Flow from Operating Activities

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.

2013

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

Cash Flow from Investing Activities

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.

2013

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

Cash Flow from Financing Activities

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. Purchases may be increased, decreased or discontinued at any time without prior notice.

2013

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

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

During 2013, Exxon Mobil Corporation purchased 177 million shares of its common stock for the treasury at a gross cost of $16.0 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 3.7 percent from 4,502 million to 4,335 million at the end of 2013. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2014. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

Commitments	Note Reference Number	Payments Due by Period 2015	2016-2019	2020 and Beyond	Total
			(millions of dollars)		
Long-term debt *(1)*	14	-	6,755	4,898	11,653
– Due in one year *(2)*	6	770	-	-	770
Asset retirement obligations *(3)*	9	1,055	2,763	9,606	13,424
Pension and other postretirement obligations *(4)*	17	1,524	4,346	20,664	26,534
Operating leases *(5)*	11	2,034	2,883	1,296	6,213
Unconditional purchase obligations *(6)*	16	150	608	337	1,095
Take-or-pay obligations *(7)*		2,973	10,671	14,065	27,709
Firm capital commitments *(8)*		16,065	7,893	1,643	25,601

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 $9.0 billion as of December 31, 2014, because the Corporation is unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can be found in Note 19, Income, Sales-Based and Other Taxes.

Notes:

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

(2) The amount due in one year is included in notes and loans payable of $17,468 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 2015 and estimated benefit payments for unfunded plans in all years.

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

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $1,095 million mainly pertain to pipeline throughput agreements and include $433 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 $27,709 million mainly pertain to pipeline, manufacturing supply and terminal agreements.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $25.6 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $13.9 billion was associated with projects in Africa, Canada, Australia, United Arab Emirates, Malaysia and Kazakhstan. The Corporation expects to fund the majority of these projects with internally generated funds, supplemented by long-term and short-term debt.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2014, 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, 2014, the Corporation's unused short-term committed lines of credit totaled approximately $6.3 billion (Note 6) and unused long-term committed lines of credit totaled approximately $0.5 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.

	2014	2013	2012
Fixed-charge coverage ratio (times)	46.9	55.7	62.4
Debt to capital (percent)	13.9	11.2	6.3
Net debt to capital (percent)	11.9	9.1	1.2

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.

CAPITAL AND EXPLORATION EXPENDITURES

	2014			2013		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
			(millions of dollars)			
Upstream *(1)*	9,401	23,326	32,727	9,145	29,086	38,231
Downstream	1,310	1,724	3,034	951	1,462	2,413
Chemical	1,690	1,051	2,741	963	869	1,832
Other	35	-	35	13	-	13
Total	12,436	26,101	38,537	11,072	31,417	42,489

(1) Exploration expenses included.

Capital and exploration expenditures in 2014 were $38.5 billion, down 9 percent from 2013 due primarily to the absence of the $3.1 billion Celtic Exploration Ltd. acquisition in 2013. The Corporation anticipates an average investment profile of about $34 billion per year for the next few years. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $32.7 billion in 2014 was down 14 percent from 2013, reflecting the absence of $4.2 billion of property acquisition costs in 2013. Investments in 2014 included projects in the U.S. Gulf of Mexico, U.S. onshore drilling, exploration in Russia 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 65 percent of total proved reserves at year-end 2014, and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved from undeveloped to developed status.

Capital investments in the Downstream totaled $3.0 billion in 2014, an increase of $0.6 billion from 2013, mainly reflecting higher spending on crude oil transportation infrastructure. The Chemical capital expenditures of $2.7 billion increased $0.9 billion from 2013 with higher investments in the U.S.

TAXES

	2014	2013	2012
		(millions of dollars)	
Income taxes	18,015	24,263	31,045
Effective income tax rate	*41%*	*48%*	*44%*
Sales-based taxes	29,342	30,589	32,409
All other taxes and duties	35,515	36,396	38,857
Total	82,872	91,248	102,311

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.

2013

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

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2014	2013
	(millions of dollars)	
Capital expenditures	2,666	2,474
Other expenditures	3,522	3,538
Total	6,188	6,012

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 2014 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $6.2 billion. The total cost for such activities is expected to remain in this range in 2015 and 2016 (with capital expenditures approximately 40 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 2014 for environmental liabilities were $780 million ($321 million in 2013) and the balance sheet reflects accumulated liabilities of $1,066 million as of December 31, 2014, and $773 million as of December 31, 2013.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2014	2013	2012
Crude oil and NGL ($/barrel)	87.42	97.48	100.29
Natural gas ($/kcf)	4.68	4.60	3.90

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $350 million annual after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a $0.10 per kcf change in the worldwide average gas realization would have approximately a $175 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide broad indicators of changes in the earnings experienced in any particular period.

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

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 political events, OPEC actions and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the Corporation evaluates the viability of all of its investments over a broad range of future prices. The Corporation's assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management programs.

The Corporation has an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing to the Corporation's strategic objectives. The result is an efficient capital base, and the Corporation has seldom had to write down the carrying value of assets, even during periods of low commodity prices.

Risk Management

The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact of such changes. With respect to derivatives activities, the Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivatives described in Note 13. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries floating interest rates. The impact of a 100-basis-point change in interest rates affecting the Corporation's debt would not be material to earnings, cash flow or fair value. The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, 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. Increased demand for certain services and materials has resulted in higher operating and capital costs in recent years. 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.

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, 2017. ExxonMobil is evaluating 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 are more likely to be recovered than not.

The estimation of proved reserves is an ongoing process based on rigorous technical evaluations, commercial and market assessment, and detailed analysis of well information such as flow rates and reservoir pressure declines. The estimation of proved reserves is controlled by the Corporation through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Reserves Technical Oversight group which has significant technical experience, culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation. Key features of the reserve estimation process are covered in Disclosure of Reserves in Item 2 of ExxonMobil's 2014 Form 10-K.

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 65 percent of total proved reserves at year-end 2014 (including both consolidated and equity company reserves), and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved from undeveloped to developed status.

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

Impact of Oil and Gas Reserves on Depreciation. The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. It is the ratio of actual volumes produced to total proved reserves or proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), applied to the asset cost. The volumes produced and asset cost are known and, while proved reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. While the revisions the Corporation has made in the past are an indicator of variability, they have had a very small impact on the unit-of-production rates because they have been small compared to the large reserves base.

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

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

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses assist the Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. Potential trigger events for impairment evaluation include a significant decrease in current and projected reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected, and current period operating losses combined with a history and forecast of operating or cash flow losses.

In general, the Corporation does not view temporarily low prices or margins as a trigger event for conducting the impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry prices over the long term, and these cannot be accurately predicted.

Accordingly, any impairment tests that the Corporation performs make use of the Corporation's price assumptions developed in the annual planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on field production profiles, which are updated annually. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to consolidated financial statements. Future prices used for any impairment tests will vary from the ones used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations are disclosed in Note 9 to the financial statements.

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in Note 10 to the financial statements.

Consolidations

The Consolidated Financial Statements include the accounts of those subsidiaries that the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in the underlying net assets of other significant entities that it does not control, but over which it exercises significant influence, are accounted for using the equity method of accounting.

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

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. Book reserves are established for these plans because tax conventions and regulatory practices do not encourage advance funding. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

For funded plans, including those in the U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in compliance with the requirements of governmental authorities and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, these standards often require approaches and assumptions that differ from those used for accounting purposes.

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

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2014 was 7.25 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 7 percent and 10 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 $170 million before tax.

Differences between actual returns on fund assets and the long-term expected return are not recognized in pension expense in the year that the difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees.

Litigation Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The status of significant claims is summarized in Note 16.

The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable, and the amount can be reasonably estimated. These amounts are not reduced by amounts that may be recovered under insurance or claims against third parties, but undiscounted receivables from insurers or other third parties may be accrued separately. The Corporation revises such accruals in light of new information. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our litigation contingency disclosures, "significant" includes material matters as well as other items which management believes should be disclosed.

Management judgment is required related to contingent liabilities and the outcome of litigation because both are difficult to predict. However, the Corporation has been successful in defending litigation in the past. Payments have not had a material adverse effect on operations or financial condition. In the Corporation's experience, large claims often do not result in large awards. Large awards are often reversed or substantially reduced as a result of appeal or settlement.

Tax Contingencies

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

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained 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, 2014.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2014, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson
Chief Executive Officer

Andrew P. Swiger
Senior Vice President
(Principal Financial Officer)

David S. Rosenthal
Vice President and Controller
(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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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, 2014, 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.

PricewaterhouseCoopers LLP

Dallas, Texas
February 25, 2015

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2014	2013	2012
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		394,105	420,836	451,509
Income from equity affiliates	7	13,323	13,927	15,010
Other income		4,511	3,492	14,162
Total revenues and other income		411,939	438,255	480,681
Costs and other deductions				
Crude oil and product purchases		225,972	244,156	263,535
Production and manufacturing expenses		40,859	40,525	38,521
Selling, general and administrative expenses		12,598	12,877	13,877
Depreciation and depletion		17,297	17,182	15,888
Exploration expenses, including dry holes		1,669	1,976	1,840
Interest expense		286	9	327
Sales-based taxes *(1)*	19	29,342	30,589	32,409
Other taxes and duties	19	32,286	33,230	35,558
Total costs and other deductions		360,309	380,544	401,955
Income before income taxes		51,630	57,711	78,726
Income taxes	19	18,015	24,263	31,045
Net income including noncontrolling interests		33,615	33,448	47,681
Net income attributable to noncontrolling interests		1,095	868	2,801
Net income attributable to ExxonMobil		32,520	32,580	44,880
Earnings per common share *(dollars)*	12	7.60	7.37	9.70
Earnings per common share - assuming dilution *(dollars)*	12	7.60	7.37	9.70

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

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2014	2013	2012
		(millions of dollars)	
Net income including noncontrolling interests	33,615	33,448	47,681
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(5,847)	(3,620)	920
Adjustment for foreign exchange translation (gain)/loss included in net income	152	(23)	(4,352)
Postretirement benefits reserves adjustment (excluding amortization)	(4,262)	3,174	(3,574)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,111	1,820	2,395
Unrealized change in fair value of stock investments	(63)	-	-
Realized (gain)/loss from stock investments included in net income	3	-	-
Total other comprehensive income	(8,906)	1,351	(4,611)
Comprehensive income including noncontrolling interests	24,709	34,799	43,070
Comprehensive income attributable to noncontrolling interests	421	760	1,251
Comprehensive income attributable to ExxonMobil	24,288	34,039	41,819

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2014	Dec. 31 2013
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		4,616	4,644
Cash and cash equivalents - restricted		42	269
Notes and accounts receivable, less estimated doubtful amounts	6	28,009	33,152
Inventories			
Crude oil, products and merchandise	3	12,384	12,117
Materials and supplies		4,294	4,018
Other current assets		3,565	5,108
Total current assets		52,910	59,308
Investments, advances and long-term receivables	8	35,239	36,328
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	252,668	243,650
Other assets, including intangibles, net		8,676	7,522
Total assets		349,493	346,808
Liabilities			
Current liabilities			
Notes and loans payable	6	17,468	15,808
Accounts payable and accrued liabilities	6	42,227	48,085
Income taxes payable		4,938	7,831
Total current liabilities		64,633	71,724
Long-term debt	14	11,653	6,891
Postretirement benefits reserves	17	25,802	20,646
Deferred income tax liabilities	19	39,230	40,530
Long-term obligations to equity companies		5,325	4,742
Other long-term obligations		21,786	21,780
Total liabilities		168,429	166,313
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		10,792	10,077
Earnings reinvested		408,384	387,432
Accumulated other comprehensive income		(18,957)	(10,725)
Common stock held in treasury (3,818 million shares in 2014 and 3,684 million shares in 2013)		(225,820)	(212,781)
ExxonMobil share of equity		174,399	174,003
Noncontrolling interests		6,665	6,492
Total equity		181,064	180,495
Total liabilities and equity		349,493	346,808

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2014	2013	2012
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		33,615	33,448	47,681
Adjustments for noncash transactions				
Depreciation and depletion		17,297	17,182	15,888
Deferred income tax charges/(credits)		1,540	754	3,142
Postretirement benefits expense in excess of/(less than) net payments		524	2,291	(315)
Other long-term obligation provisions in excess of/(less than) payments		1,404	(2,566)	1,643
Dividends received greater than/(less than) equity in current earnings of equity companies		(358)	3	(1,157)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		3,118	(305)	(1,082)
- Inventories		(1,343)	(1,812)	(1,873)
- Other current assets		(68)	(105)	(42)
Increase/(reduction) - Accounts and other payables		(6,639)	(2,498)	3,624
Net (gain) on asset sales	5	(3,151)	(1,828)	(13,018)
All other items - net		(823)	350	1,679
Net cash provided by operating activities		45,116	44,914	56,170
Cash flows from investing activities				
Additions to property, plant and equipment		(32,952)	(33,669)	(34,271)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	4,035	2,707	7,655
Decrease/(increase) in restricted cash and cash equivalents		227	72	63
Additional investments and advances		(1,631)	(4,435)	(598)
Collection of advances		3,346	1,124	1,550
Net cash used in investing activities		(26,975)	(34,201)	(25,601)
Cash flows from financing activities				
Additions to long-term debt		5,731	345	995
Reductions in long-term debt		(69)	(13)	(147)
Additions to short-term debt		-	16	958
Reductions in short-term debt		(745)	(756)	(4,488)
Additions/(reductions) in debt with three months or less maturity		2,049	12,012	(226)
Cash dividends to ExxonMobil shareholders		(11,568)	(10,875)	(10,092)
Cash dividends to noncontrolling interests		(248)	(304)	(327)
Changes in noncontrolling interests		-	(1)	204
Tax benefits related to stock-based awards		115	48	130
Common stock acquired		(13,183)	(15,998)	(21,068)
Common stock sold		30	50	193
Net cash used in financing activities		(17,888)	(15,476)	(33,868)
Effects of exchange rate changes on cash		(281)	(175)	217
Increase/(decrease) in cash and cash equivalents		(28)	(4,938)	(3,082)
Cash and cash equivalents at beginning of year		4,644	9,582	12,664
Cash and cash equivalents at end of year		4,616	4,644	9,582

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, 2011	9,512	330,939	(9,123)	(176,932)	154,396	6,348	160,744
Amortization of stock-based awards	806	-	-	-	806	-	806
Tax benefits related to stock-based awards	178	-	-	-	178	-	178
Other	(843)	-	-	-	(843)	(1,441)	(2,284)
Net income for the year	-	44,880	-	-	44,880	2,801	47,681
Dividends - common shares	-	(10,092)	-	-	(10,092)	(327)	(10,419)
Other comprehensive income	-	-	(3,061)	-	(3,061)	(1,550)	(4,611)
Acquisitions, at cost	-	-	-	(21,068)	(21,068)	(34)	(21,102)
Dispositions	-	-	-	667	667	-	667
Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797	171,660
Amortization of stock-based awards	761	-	-	-	761	-	761
Tax benefits related to stock-based awards	162	-	-	-	162	-	162
Other	(499)	-	-	-	(499)	240	(259)
Net income for the year	-	32,580	-	-	32,580	868	33,448
Dividends - common shares	-	(10,875)	-	-	(10,875)	(304)	(11,179)
Other comprehensive income	-	-	1,459	-	1,459	(108)	1,351
Acquisitions, at cost	-	-	-	(15,998)	(15,998)	(1)	(15,999)
Dispositions	-	-	-	550	550	-	550
Balance as of December 31, 2013	10,077	387,432	(10,725)	(212,781)	174,003	6,492	180,495
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

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2011	8,019	(3,285)	4,734
Acquisitions	-	(244)	(244)
Dispositions	-	12	12
Balance as of December 31, 2012	8,019	(3,517)	4,502
Acquisitions	-	(177)	(177)
Dispositions	-	10	10
Balance as of December 31, 2013	8,019	(3,684)	4,335
Acquisitions	-	(136)	(136)
Dispositions	-	2	2
Balance as of December 31, 2014	8,019	(3,818)	4,201

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 2014 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

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.

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

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

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

Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allowances are reviewed at least annually.

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.

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2014 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, 2017. ExxonMobil is evaluating the standard and its effect on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $971 million in 2014, $1,044 million in 2013 and $1,042 million in 2012.

Net income included before-tax aggregate foreign exchange transaction losses of $225 million, and gains of $155 million and $159 million in 2014, 2013 and 2012, respectively.

In 2014, 2013 and 2012, net income included gains of $187 million, $282 million and $328 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 $10.6 billion and $21.2 billion at December 31, 2014, and 2013, respectively.

Crude oil, products and merchandise as of year-end 2014 and 2013 consist of the following:

	2014	2013
	(billions of dollars)	
Petroleum products	4.1	3.9
Crude oil	4.6	4.7
Chemical products	2.9	2.9
Gas/other	0.8	0.6
Total	12.4	12.1

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, 2011	4,168	(13,291)	-	(9,123)
Current period change excluding amounts reclassified from accumulated other comprehensive income	842	(3,402)	-	(2,560)
Amounts reclassified from accumulated other comprehensive income	(2,600)	2,099	-	(501)
Total change in accumulated other comprehensive income	(1,758)	(1,303)	-	(3,061)
Balance as of December 31, 2012	2,410	(14,594)	-	(12,184)
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)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	**2014**	**2013**	**2012**
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	(152)	23	4,352
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs *(1)*	(1,571)	(2,616)	(3,621)
Realized change in fair value of stock investments included in net income (Statement of Income line: Other income)	(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	**2014**	**2013**	**2012**
		(millions of dollars)	
Foreign exchange translation adjustment	292	218	(236)
Postretirement benefits reserves adjustment (excluding amortization)	2,009	(1,540)	1,619
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(460)	(796)	(1,226)
Unrealized change in fair value of stock investments	34	-	-
Realized change in fair value of stock investments included in net income	(2)	-	-
Total	1,873	(2,118)	157

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 2014, the "Net (gain) on asset sales" on the Consolidated Statement of Cash Flows 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. For 2012, the amount includes before-tax gains related to the Japan restructuring, the sale of an Upstream property in Angola, exchanges of Upstream properties, the sale of U.S. service stations and the sale of Downstream affiliates in Malaysia and Switzerland. These gains are reported in "Other income" on the Consolidated Statement of Income.

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.

In 2012, the Corporation's interest in a cost company was redeemed. As part of the redemption, a variable note due in 2035 issued by Mobil Services (Bahamas) Ltd. was assigned to a consolidated ExxonMobil affiliate. This note is no longer classified as third party long-term debt. This assignment did not result in a "Reduction in long-term debt" on the Statement of Cash Flows.

In 2012, ExxonMobil completed asset exchanges, primarily noncash transactions, of approximately $1 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.

	2014	2013	2012
		(millions of dollars)	
Cash payments for interest	380	426	555
Cash payments for income taxes	18,085	25,066	24,349

6. Additional Working Capital Information

	Dec. 31 2014	Dec. 31 2013
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $113 million and $112 million	18,541	25,993
Other, less reserves of $48 million and $28 million	9,468	7,159
Total	28,009	33,152
Notes and loans payable		
Bank loans	473	723
Commercial paper	16,225	14,051
Long-term debt due within one year	770	1,034
Total	17,468	15,808
Accounts payable and accrued liabilities		
Trade payables	25,286	30,920
Payables to equity companies	6,589	6,587
Accrued taxes other than income taxes	3,290	3,883
Other	7,062	6,695
Total	42,227	48,085

The Corporation has short-term committed lines of credit of $6.3 billion which were unused as of December 31, 2014. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 0.3 percent and 0.4 percent at December 31, 2014, and 2013, respectively.

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, natural gas marketing, and refining operations 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 14 percent, 13 percent and 16 percent in the years 2014, 2013 and 2012, 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. In compliance with the sanctions and all general and specific licenses, prohibited activities involving offshore Russia in the Black Sea, Arctic regions, and onshore western Siberia have been wound down. The Corporation's maximum exposure to loss from these joint ventures as of December 31, 2014, is $1.0 billion.

Equity Company Financial Summary	2014 Total	2014 ExxonMobil Share	2013 Total	2013 ExxonMobil Share	2012 Total	2012 ExxonMobil Share
	(millions of dollars)					
Total revenues	183,708	55,855	236,161	68,084	224,953	67,572
Income before income taxes	65,549	19,014	69,454	19,999	69,411	20,882
Income taxes	20,520	5,684	21,618	6,069	20,703	5,868
Income from equity affiliates	45,029	13,330	47,836	13,930	48,708	15,014
Current assets	49,905	16,802	62,398	19,545	59,612	18,483
Long-term assets	110,754	33,619	116,450	35,695	111,131	33,798
Total assets	160,659	50,421	178,848	55,240	170,743	52,281
Current liabilities	37,333	11,472	54,550	15,243	49,698	14,265
Long-term liabilities	66,231	19,470	68,857	20,873	68,855	19,715
Net assets	57,095	19,479	55,441	19,124	52,190	18,301

A list of significant equity companies as of December 31, 2014, 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	
Chalmette Refining, LLC	50
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 USA L.P.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2014	Dec. 31, 2013
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	20,017	19,619
Advances	9,818	10,476
Total equity company investments and advances	29,835	30,095
Companies carried at cost or less and stock investments carried at fair value	526	115
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $2,662 million and $2,938 million	4,878	6,118
Total	35,239	36,328

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2014 Cost	December 31, 2014 Net	December 31, 2013 Cost	December 31, 2013 Net
	(millions of dollars)			
Upstream	347,170	205,308	336,359	197,554
Downstream	53,327	22,639	54,456	23,219
Chemical	30,717	14,918	29,487	13,965
Other	15,575	9,803	14,215	8,912
Total	446,789	252,668	434,517	243,650

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.

Accumulated depreciation and depletion totaled $194,121 million at the end of 2014 and $190,867 million at the end of 2013. Interest capitalized in 2014, 2013 and 2012 was $344 million, $309 million and $506 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:

	2014	2013
	(millions of dollars)	
Beginning balance	12,988	11,973
Accretion expense and other provisions	871	785
Reduction due to property sales	(151)	(97)
Payments made	(724)	(664)
Liabilities incurred	122	603
Foreign currency translation	(908)	(344)
Revisions	1,226	732
Ending balance	13,424	12,988

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:

	2014	2013	2012
		(millions of dollars)	
Balance beginning at January 1	2,707	2,679	2,881
Additions pending the determination of proved reserves	1,095	293	868
Charged to expense	(28)	(52)	(95)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(160)	(107)	(631)
Divestments/Other	(27)	(106)	(344)
Ending balance at December 31	3,587	2,707	2,679
Ending balance attributed to equity companies included above	645	13	3

Period end capitalized suspended exploratory well costs:

	2014	2013	2012
		(millions of dollars)	
Capitalized for a period of one year or less	1,095	293	866
Capitalized for a period of between one and five years	1,659	1,705	1,176
Capitalized for a period of between five and ten years	544	470	401
Capitalized for a period of greater than ten years	289	239	236
Capitalized for a period greater than one year - subtotal	2,492	2,414	1,813
Total	3,587	2,707	2,679

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

	2014	2013	2012
Number of projects with first capitalized well drilled in the preceding 12 months	8	8	10
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	53	50	45
Total	61	58	55

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Of the 53 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2014, 15 projects have drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 38 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 38 projects, which total $1,035 million.

Country/Project	Dec. 31, 2014	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 infrastructure.
Australia			
- East Pilchard	8	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Longtom	12	2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Remora	38	2010	Gas field near Marlin development, awaiting capacity in existing/planned infrastructure.
Indonesia			
- Alas Tua West	16	2010	Evaluating development plan to tie into planned production facilities.
- Cepu Gas	28	2008 - 2011	Development activity under way, while continuing commercial discussions with the 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 government on contract terms pursuant to executed Heads of Agreement.
Kazakhstan			
- Kairan	53	2004 - 2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
Malaysia			
- Besar	18	1992 - 2010	Gas field off the east coast of Malaysia; progressing development plan.
- Bindu	2	1995	Awaiting capacity in existing/planned infrastructure.
Nigeria			
- Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bosi	79	2002 - 2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Bosi Central	16	2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Erha Northeast	26	2008	Evaluating development plan for tieback to existing production facilities.
- Owowo	50	2009 - 2012	Continuing discussions with the government regarding contract terms.
- 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	15	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Lavrans	18	1995 - 1999	Evaluating development plan, awaiting capacity in existing Kristin production facility.
- Other (7 projects)	29	2008 - 2013	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Progressing development plans to tie into existing LNG facilities.
- P'nyang	58	2012	Evaluating development alternatives to tie into existing/planned infrastructure.
Republic of Congo			
- Mer Tres Profonde Sud	56	2000 - 2007	Evaluating development alternatives, while continuing discussions with the government 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 2014 (38 projects)	1,035		

11. Leased Facilities

At December 31, 2014, 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 $6,213 million as indicated in the table. Estimated related rental income from noncancelable subleases is $70 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	(millions of dollars)	
2015	2,034	31
2016	1,379	7
2017	774	6
2018	418	3
2019	312	3
2020 and beyond	1,296	20
Total	6,213	70

Net rental cost under both cancelable and noncancelable operating leases incurred during 2014, 2013 and 2012 were as follows:

	2014	2013	2012
		(millions of dollars)	
Rental cost	4,077	3,841	3,851
Less sublease rental income	52	44	44
Net rental cost	4,025	3,797	3,807

12. Earnings Per Share

	2014	2013	2012
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	32,520	32,580	44,880
Weighted average number of common shares outstanding *(millions of shares)*	4,282	4,419	4,628
Earnings per common share *(dollars) (1)*	7.60	7.37	9.70
Dividends paid per common share *(dollars)*	2.70	2.46	2.18

(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 $11.7 billion and $6.8 billion at December 31, 2014, and 2013, respectively, as compared to recorded book values of $11.3 billion and $6.5 billion at December 31, 2014, and 2013, respectively. The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $5,500 million of long-term debt in the first quarter of 2014.

The fair value of long-term debt by hierarchy level at December 31, 2014, is: Level 1 $11,036 million; Level 2 $561 million; and Level 3 $63 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 $75 million at year-end 2014 and a net asset of $1 million at year-end 2013. 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 $110 million, $(7) million and $(23) million during 2014, 2013 and 2012, 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.

14. Long-Term Debt

At December 31, 2014, long-term debt consisted of $11,341 million due in U.S. dollars and $312 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 $770 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 $5,500 million of long-term debt in the first quarter of 2014. The amounts of long-term debt maturing in each of the four years after December 31, 2015, in millions of dollars, are: 2016 – $537; 2017 – $2,993; 2018 – $872; and 2019 – $2,353. At December 31, 2014, the Corporation's unused long-term credit lines were $0.5 billion.

Summarized long-term debt at year-end 2014 and 2013 are shown in the table below:

	2014	2013
	(millions of dollars)	
Exxon Mobil Corporation		
0.921% notes due 2017	1,500	-
Floating-rate notes due 2017 *(1)*	750	-
1.819% notes due 2019	1,750	-
Floating-rate notes due 2019 *(2)*	500	-
3.176% notes due 2024	1,000	-
XTO Energy Inc. *(3)*		
5.000% senior notes due 2015	-	132
5.300% senior notes due 2015	-	243
5.650% senior notes due 2016	207	212
6.250% senior notes due 2017	477	489
5.500% senior notes due 2018	383	389
6.500% senior notes due 2018	474	485
6.100% senior notes due 2036	199	200
6.750% senior notes due 2037	309	312
6.375% senior notes due 2038	236	238
Mobil Producing Nigeria Unlimited *(4)*		
Variable notes due 2015-2019	399	742
Esso (Thailand) Public Company Ltd. *(5)*		
Variable notes due 2015-2019	121	177
Mobil Corporation		
8.625% debentures due 2021	249	249
Industrial revenue bonds due 2015-2051 *(6)*	2,611	2,527
Other U.S. dollar obligations *(7)*	104	112
Other foreign currency obligations	9	9
Capitalized lease obligations *(8)*	375	375
Total long-term debt	11,653	6,891

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

(2) Average effective interest rate of 0.4% in 2014.

(3) Includes premiums of $219 million in 2014 and $271 million in 2013.

(4) Average effective interest rate of 4.5% in 2014 and 4.6% in 2013.

(5) Average effective interest rate of 2.4% in 2014 and 3.3% in 2013.

(6) Average effective interest rate of 0.03% in 2014 and 0.06% in 2013.

(7) Average effective interest rate of 4.2% in 2014 and 4.4% in 2013.

(8) Average imputed interest rate of 7.0% in 2014 and 7.8% in 2013.

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 2014, remaining shares available for award under the 2003 Incentive Program were 108 million.

Restricted Stock and Restricted Stock Units. Awards totaling 9,775 thousand, 9,729 thousand, and 10,017 thousand of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2014, 2013 and 2012, 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, 2014.

	2014	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	45,207	78.29
2013 award issued in 2014	9,705	94.47
Vested	(10,286)	79.89
Forfeited	(187)	78.89
Issued and outstanding at December 31	44,439	81.45

Value of restricted stock and units	**2014**	**2013**	**2012**
Grant price *(dollars)*	95.20	94.47	87.24
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	858	843	797
Units settled in cash	73	76	77
Total value	931	919	874

As of December 31, 2014, there was $2,339 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 $831 million, $854 million and $854 million for 2014, 2013 and 2012, respectively. The income tax benefit recognized in income related to this compensation expense was $76 million, $78 million and $79 million for the same periods, respectively. The fair value of shares and units vested in 2014, 2013 and 2012 was $946 million, $1,040 million and $926 million, respectively. Cash payments of $73 million, $67 million and $66 million for vested restricted stock units settled in cash were made in 2014, 2013 and 2012, respectively.

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, 2014, 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, 2014		
	Equity Company Obligations *(1)*	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees			
Debt-related	3,506	41	3,547
Other	2,920	3,982	6,902
Total	6,426	4,023	10,449

(1) ExxonMobil share.

The debt-related guarantees shown above include a $3.4 billion completion guarantee provided to lenders in support of the project financing for the Papua New Guinea Liquefied Natural Gas project. On February 4, 2015, the obligations under this guarantee were terminated per the terms of the loan agreement.

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			
	2015	2016-2019	2020 and Beyond	Total
		(millions of dollars)		
Unconditional purchase obligations *(1)*	150	608	337	1,095

(1) Undiscounted obligations of $1,095 million mainly pertain to pipeline throughput agreements and include $433 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of $168 million, totaled $927 million.

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and owned by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulation that if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assume the activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by 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) invoking ICSID jurisdiction under Venezuela's Investment Law and the Netherlands-Venezuela Bilateral Investment Treaty. 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 (ICC). Following the favorable ICSID decision in the fourth quarter of 2014, ExxonMobil recognized earnings of $269 million, net of the remaining asset value, for the proceeds received from the earlier ICC award.

Judgment was entered on the ICSID award by the United States District Court for the Southern District of New York on October 10, 2014. A motion to vacate that judgment on procedural grounds was filed by the Republic of Venezuela on October 14, 2014, which was denied by the court. Thereafter, the Republic of Venezuela filed a motion 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.

On October 23, 2014, the Republic of Venezuela filed with ICSID an application to revise the ICSID award such that it requires repayment of the value of the ICC award to PdVSA at the same time as payment is made to the ExxonMobil affiliates for the ICSID award and that provision be made for interest on the amount to be repaid. Thereafter, pursuant to ICSID arbitration rules, the ICSID award was stayed pending further action of the Tribunal. On October 27, 2014, ExxonMobil filed a response with ICSID that contests the application for revision of that award on both factual and jurisdictional grounds. On February 2, 2015, the Republic of Venezuela filed an application to annul the ICSID award. The 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. Upon registration of the application with ICSID on February 9, 2015, a further stay of the ICSID award was entered.

The federal court in New York has stayed its judgment until such time as the stays of the ICSID award entered following the Government of Venezuela's filing of its two applications have 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 have appealed that judgment. 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. 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.

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.			
	2014	2013	2014	2013	2014	2013
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.00	5.00	3.10	4.30	4.00	5.00
Long-term rate of compensation increase	5.75	5.75	5.30	5.40	5.75	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	17,304	19,779	27,357	28,670	7,868	9,058
Service cost	677	801	590	697	140	176
Interest cost	807	749	1,138	1,076	383	352
Actuarial loss/(gain)	3,192	(1,520)	4,929	(1,454)	1,522	(1,267)
Benefits paid *(1) (2)*	(1,427)	(2,520)	(1,366)	(1,311)	(525)	(511)
Foreign exchange rate changes	-	-	(2,540)	(284)	(48)	(43)
Amendments, divestments and other	(24)	15	(61)	(37)	96	103
Benefit obligation at December 31	20,529	17,304	30,047	27,357	9,436	7,868
Accumulated benefit obligation at December 31	16,385	13,989	26,318	23,949	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2014 and 2013, other postretirement benefits paid are net of $21 million and $20 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 2016 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $91 million and the postretirement benefit obligation by $1,070 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $69 million and the postretirement benefit obligation by $844 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2014	2013	2014	2013	2014	2013
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	11,190	12,632	19,283	18,090	620	581
Actual return on plan assets	1,497	617	3,153	1,604	41	64
Foreign exchange rate changes	-	-	(1,738)	(270)	-	-
Company contribution	1,476	101	554	919	31	35
Benefits paid *(1)*	(1,248)	(2,171)	(912)	(869)	(224)	(60)
Other	-	11	(245)	(191)	-	-
Fair value at December 31	12,915	11,190	20,095	19,283	468	620

(1) Benefit payments for funded plans.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2014	2013	2014	2013
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,590)	(3,547)	(2,113)	(941)
Unfunded plans	(3,024)	(2,567)	(7,839)	(7,133)
Total	(7,614)	(6,114)	(9,952)	(8,074)

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.			
	2014	2013	2014	2013	2014	2013
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(7,614)	(6,114)	(9,952)	(8,074)	(8,968)	(7,248)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	-	1	302	201	-	-
Current liabilities	(340)	(275)	(325)	(358)	(369)	(359)
Postretirement benefits reserves	(7,274)	(5,840)	(9,929)	(7,917)	(8,599)	(6,889)
Total recorded	(7,614)	(6,114)	(9,952)	(8,074)	(8,968)	(7,248)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	6,589	4,780	9,642	7,943	2,997	1,603
Prior service cost	27	60	429	665	51	65
Total recorded in accumulated other comprehensive income	6,616	4,840	10,071	8,608	3,048	1,668

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

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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.					
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*				
Discount rate	5.00	4.00	5.00	4.30	3.80	4.00	5.00	4.00	5.00
Long-term rate of return on funded assets	7.25	7.25	7.25	6.30	6.40	6.60	7.25	7.25	7.25
Long-term rate of compensation increase	5.75	5.75	5.75	5.40	5.50	5.40	5.75	5.75	5.75
Components of net periodic benefit cost					*(millions of dollars)*				
Service cost	677	801	665	590	697	648	140	176	134
Interest cost	807	749	820	1,138	1,076	1,145	383	352	380
Expected return on plan assets	(799)	(835)	(789)	(1,193)	(1,128)	(1,109)	(37)	(41)	(38)
Amortization of actuarial loss/(gain)	409	646	576	628	852	844	116	228	170
Amortization of prior service cost	8	7	7	120	117	117	14	21	34
Net pension enhancement and curtailment/settlement cost *(1)*	276	723	333	-	22	1,540	-	-	-
Net periodic benefit cost	1,378	2,091	1,612	1,283	1,636	3,185	616	736	680

(1) Non-U.S. net pension enhancement and curtailment/settlement cost for 2012 includes $1,420 million (on a consolidated-company, before-tax basis) of accumulated other comprehensive income for the postretirement benefit reserves adjustment that was recycled into earnings and included in the Japan restructuring gain reported in "Other income".

	U.S. 2014	U.S. 2013	U.S. 2012	Non-U.S. 2014	Non-U.S. 2013	Non-U.S. 2012	Other 2014	Other 2013	Other 2012
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	2,494	(1,302)	1,885	2,969	(1,938)	1,906	1,518	(1,290)	1,008
Amortization of actuarial (loss)/gain	(685)	(1,369)	(909)	(628)	(874)	(2,384)	(116)	(228)	(170)
Prior service cost/(credit)	(25)	-	-	(70)	30	71	-	-	-
Amortization of prior service (cost)/credit	(8)	(7)	(7)	(120)	(117)	(117)	(14)	(21)	(34)
Foreign exchange rate changes	-	-	-	(688)	(155)	271	(8)	(10)	3
Total recorded in other comprehensive income	1,776	(2,678)	969	1,463	(3,054)	(253)	1,380	(1,549)	807
Total recorded in net periodic benefit cost and other comprehensive income, before tax	3,154	(587)	2,581	2,746	(1,418)	2,932	1,996	(813)	1,487

Costs for defined contribution plans were $393 million, $392 million and $382 million in 2014, 2013 and 2012, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2014	2013	2012
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	(1,776)	2,678	(969)
Non-U.S. pension	(1,463)	3,054	253
Other postretirement benefits	(1,380)	1,549	(807)
Total (charge)/credit to other comprehensive income, before tax	(4,619)	7,281	(1,523)
(Charge)/credit to income tax (see Note 4)	1,549	(2,336)	393
(Charge)/credit to investment in equity companies	(81)	49	(49)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	(3,151)	4,994	(1,179)
Charge/(credit) to equity of noncontrolling interests	85	(279)	(124)
(Charge)/credit to other comprehensive income attributable to ExxonMobil	(3,066)	4,715	(1,303)

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 for the non-U.S. plans in aggregate 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.

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				Non-U.S. Pension			
	Fair Value Measurement at December 31, 2014, Using:				Fair Value Measurement at December 31, 2014, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (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.

	Other Postretirement			
	Fair Value Measurement at December 31, 2014, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (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

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The 2013 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, 2013, Using:				Non-U.S. Pension Fair Value Measurement at December 31, 2013, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	2,514 *(1)*	-	2,514	-	3,046 *(1)*	-	3,046
Non-U.S.	-	2,622 *(1)*	-	2,622	294 *(2)*	5,608 *(1)*	-	5,902
Private equity	-	-	523 *(3)*	523	-	-	502 *(3)*	502
Debt securities								
Corporate	-	3,430 *(4)*	-	3,430	-	2,125 *(4)*	-	2,125
Government	-	2,056 *(4)*	-	2,056	272 *(5)*	7,100 *(4)*	-	7,372
Asset-backed	-	6 *(4)*	-	6	-	103 *(4)*	-	103
Real estate funds	-	-	-	-	-	-	136 *(6)*	136
Cash	-	27 *(7)*	-	27	57	20 *(8)*	-	77
Total at fair value	-	10,655	523	11,178	623	18,002	638	19,263
Insurance contracts at contract value				12				20
Total plan assets				11,190				19,283

(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.

	Other Postretirement			
	Fair Value Measurement at December 31, 2013, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	157 *(1)*	-	157
Non-U.S.	-	149 *(1)*	-	149
Private equity	-	-	9 *(2)*	9
Debt securities				
Corporate	-	129 *(3)*	-	129
Government	-	168 *(3)*	-	168
Asset-backed	-	4 *(3)*	-	4
Cash	-	4	-	4
Total at fair value	-	611	9	620

(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 2013 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2013			
	Pension			Other Postretirement
	U.S.	Non-U.S.		
	Private Equity	Private Equity	Real Estate	Private Equity
	(millions of dollars)			
Fair value at January 1	489	448	293	7
Net realized gains/(losses)	(1)	11	(13)	-
Net unrealized gains/(losses)	86	57	10	3
Net purchases/(sales)	(51)	(14)	(154)	(1)
Fair value at December 31	523	502	136	9

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.	
	2014	2013	2014	2013
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	17,505	14,737	5,031	891
Accumulated benefit obligation	14,493	12,342	4,590	689
Fair value of plan assets	12,915	11,189	3,890	611
For unfunded pension plans:				
Projected benefit obligation	3,024	2,567	7,839	7,133
Accumulated benefit obligation	1,892	1,647	6,573	6,070

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2015 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	1,001	753	211
Prior service cost *(2)*	6	105	14

(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 2015	-	560	-	-
Benefit payments expected in:				
2015	1,628	1,194	467	24
2016	1,554	1,213	479	25
2017	1,529	1,278	490	26
2018	1,445	1,298	499	28
2019	1,410	1,339	507	29
2020 - 2024	6,714	6,988	2,613	172

18. Disclosures about Segments and Related Information

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

These functions have been defined as the operating segments of the Corporation because they are the segments (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Corporation's chief operating decision maker to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which discrete financial information is available.

Earnings after income tax include transfers at estimated market prices.

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In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $129 million and $202 million in 2014 and 2012, respectively. For 2013, non-debt-related interest expense was a net credit of $123 million, primarily reflecting the effect of credits from the favorable resolution of prior year tax positions.

	Upstream		Downstream		Chemical		Corporate and	Corporate
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	Total
				(millions of dollars)				
As of December 31, 2014								
Earnings after income tax	5,197	22,351	1,618	1,427	2,804	1,511	(2,388)	32,520
Earnings of equity companies included above	1,235	10,859	29	82	186	1,377	(445)	13,323
Sales and other operating revenue *(1)*	14,826	22,336	118,771	199,976	15,115	23,063	18	394,105
Intersegment revenue	7,723	38,846	17,281	44,231	10,117	8,098	274	-
Depreciation and depletion expense	5,139	8,523	654	1,228	370	645	738	17,297
Interest revenue	-	-	-	-	-	-	75	75
Interest expense	40	17	6	4	-	-	219	286
Income taxes	1,300	15,165	610	968	1,032	358	(1,418)	18,015
Additions to property, plant and equipment	9,098	19,225	1,050	1,356	1,564	564	1,399	34,256
Investments in equity companies	5,089	10,877	69	1,006	258	3,026	(308)	20,017
Total assets	92,555	161,033	18,371	33,299	8,798	18,449	16,988	349,493
As of December 31, 2013								
Earnings after income tax	4,191	22,650	2,199	1,250	2,755	1,073	(1,538)	32,580
Earnings of equity companies included above	1,576	11,627	(460)	22	189	1,422	(449)	13,927
Sales and other operating revenue *(1)*	13,712	25,349	123,802	218,904	15,295	23,753	21	420,836
Intersegment revenue	8,343	45,761	20,781	52,624	11,993	8,232	285	-
Depreciation and depletion expense	5,170	8,277	633	1,390	378	632	702	17,182
Interest revenue	-	-	-	-	-	-	87	87
Interest expense	30	26	7	8	1	-	(63)	9
Income taxes	2,197	21,554	721	481	989	363	(2,042)	24,263
Additions to property, plant and equipment	7,480	26,075	616	1,072	840	272	1,386	37,741
Investments in equity companies	4,975	9,740	62	1,749	217	3,103	(227)	19,619
Total assets	88,698	157,465	19,261	40,661	7,816	19,659	13,248	346,808
As of December 31, 2012								
Earnings after income tax	3,925	25,970	3,575	9,615	2,220	1,678	(2,103)	44,880
Earnings of equity companies included above	1,759	11,900	6	387	183	1,267	(492)	15,010
Sales and other operating revenue *(1)*	11,039	27,673	125,088	248,959	14,723	24,003	24	451,509
Intersegment revenue	8,764	47,507	20,963	62,130	12,409	9,750	258	-
Depreciation and depletion expense	5,104	7,340	594	1,280	376	508	686	15,888
Interest revenue	-	-	-	-	-	-	117	117
Interest expense	37	13	3	36	-	(1)	239	327
Income taxes	2,025	25,362	1,811	1,892	755	232	(1,032)	31,045
Additions to property, plant and equipment	9,697	21,769	480	1,153	338	659	1,083	35,179
Investments in equity companies	4,020	9,147	195	2,069	233	3,143	(277)	18,530
Total assets	86,146	140,848	18,451	40,956	7,238	18,886	21,270	333,795

(1) Sales and other operating revenue includes sales-based taxes of $29,342 million for 2014, $30,589 million for 2013 and $32,409 million for 2012. See Note 1, Summary of Accounting Policies.

Geographic

Sales and other operating revenue (1)	2014	2013	2012
		(millions of dollars)	
United States	148,713	152,820	150,865
Non-U.S.	245,392	268,016	300,644
Total	394,105	420,836	451,509
Significant non-U.S. revenue sources include:			
Canada	36,072	35,924	34,325
United Kingdom	31,346	34,061	33,600
Belgium	20,953	20,973	23,567
Italy	18,880	19,273	18,228
France	17,639	18,444	19,601
Singapore	15,407	15,623	14,606
Germany	14,816	15,701	15,871

(1) Sales and other operating revenue includes sales-based taxes of $29,342 million for 2014, $30,589 million for 2013 and $32,409 million for 2012. See Note 1, Summary of Accounting Policies.

Long-lived assets	2014	2013	2012
		(millions of dollars)	
United States	104,000	98,271	94,336
Non-U.S.	148,668	145,379	132,613
Total	252,668	243,650	226,949
Significant non-U.S. long-lived assets include:			
Canada	43,858	41,522	31,979
Australia	15,328	14,258	13,415
Nigeria	12,265	12,343	12,216
Singapore	9,620	9,570	9,700
Kazakhstan	9,138	8,530	7,785
Angola	9,057	8,262	8,238
Papua New Guinea	6,099	5,768	4,599
Norway	5,139	6,542	7,040

19. Income, Sales-Based and Other Taxes

	2014			2013			2012		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Income tax expense									
Federal and non-U.S.									
Current	1,456	14,755	16,211	1,073	22,115	23,188	1,791	25,650	27,441
Deferred - net	900	1,398	2,298	(116)	757	641	1,097	1,816	2,913
U.S. tax on non-U.S. operations	5	-	5	37	-	37	89	-	89
Total federal and non-U.S.	2,361	16,153	18,514	994	22,872	23,866	2,977	27,466	30,443
State *(1)*	(499)	-	(499)	397	-	397	602	-	602
Total income tax expense	1,862	16,153	18,015	1,391	22,872	24,263	3,579	27,466	31,045
Sales-based taxes	6,310	23,032	29,342	5,992	24,597	30,589	5,785	26,624	32,409
All other taxes and duties									
Other taxes and duties	378	31,908	32,286	955	32,275	33,230	1,406	34,152	35,558
Included in production and manufacturing expenses	1,454	1,179	2,633	1,318	1,182	2,500	1,242	1,308	2,550
Included in SG&A expenses	155	441	596	150	516	666	154	595	749
Total other taxes and duties	1,987	33,528	35,515	2,423	33,973	36,396	2,802	36,055	38,857
Total	10,159	72,713	82,872	9,806	81,442	91,248	12,166	90,145	102,311

(1) In 2014, state taxes included a favorable adjustment of deferred taxes of approximately $830 million.

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expenses. The above provisions for deferred income taxes include net credits of $40 million in 2014 and $310 million in 2013 and a net charge of $244 million in 2012 for the effect of changes in tax laws and rates.

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2014, 2013 and 2012 is as follows:

	2014	2013	2012
		(millions of dollars)	
Income before income taxes			
United States	9,080	9,746	11,222
Non-U.S.	42,550	47,965	67,504
Total	51,630	57,711	78,726
Theoretical tax	18,071	20,199	27,554
Effect of equity method of accounting	(4,663)	(4,874)	(5,254)
Non-U.S. taxes in excess of theoretical U.S. tax	5,442	10,528	8,434
U.S. tax on non-U.S. operations	5	37	89
State taxes, net of federal tax benefit	(324)	258	391
Other	(516)	(1,885)	(169)
Total income tax expense	18,015	24,263	31,045
Effective tax rate calculation			
Income taxes	18,015	24,263	31,045
ExxonMobil share of equity company income taxes	5,678	6,061	5,859
Total income taxes	23,693	30,324	36,904
Net income including noncontrolling interests	33,615	33,448	47,681
Total income before taxes	57,308	63,772	84,585
Effective income tax rate	41%	48%	44%

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

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

Tax effects of temporary differences for:	**2014**	**2013**
	(millions of dollars)	
Property, plant and equipment	51,643	50,884
Other liabilities	4,359	3,474
Total deferred tax liabilities	56,002	54,358
Pension and other postretirement benefits	(8,140)	(6,573)
Asset retirement obligations	(6,162)	(6,083)
Tax loss carryforwards	(4,099)	(3,393)
Other assets	(6,446)	(6,246)
Total deferred tax assets	(24,847)	(22,295)
Asset valuation allowances	2,570	2,491
Net deferred tax liabilities	33,725	34,554

In 2014, asset valuation allowances of $2,570 million increased by $79 million and included additional net provisions of $340 million and effects of foreign currency translation of $(261) million.

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

Balance sheet classification	**2014**	**2013**
	(millions of dollars)	
Other current assets	(2,001)	(3,575)
Other assets, including intangibles, net	(3,955)	(2,822)
Accounts payable and accrued liabilities	451	421
Deferred income tax liabilities	39,230	40,530
Net deferred tax liabilities	33,725	34,554

The Corporation had $51 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. Unrecognized deferred taxes on remittance of these funds are not expected to be material.

Unrecognized Tax Benefits. The Corporation is subject to income taxation in many jurisdictions around the world. Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements. The following table summarizes the movement in unrecognized tax benefits:

Gross unrecognized tax benefits	2014	2013	2012
		(millions of dollars)	
Balance at January 1	7,838	7,663	4,922
Additions based on current year's tax positions	1,454	1,460	1,662
Additions for prior years' tax positions	448	464	2,559
Reductions for prior years' tax positions	(532)	(249)	(535)
Reductions due to lapse of the statute of limitations	(117)	(588)	(79)
Settlements with tax authorities	(43)	(849)	(855)
Foreign exchange effects/other	(62)	(63)	(11)
Balance at December 31	8,986	7,838	7,663

The gross unrecognized tax benefit balances shown above are predominantly related to tax positions that would reduce the Corporation's effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2014, 2013 and 2012 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the Corporation. It is reasonably possible that the total amount of unrecognized tax benefits could increase by up to 30 percent in the next 12 months, with no material impact on the Corporation's net income.

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

Country of Operation	Open Tax Years
Abu Dhabi	2012 - 2014
Angola	2009 - 2014
Australia:	2000 - 2003
	2005
	2008 - 2014
Canada	2007 - 2014
Equatorial Guinea	2007 - 2014
Malaysia	2008 - 2014
Nigeria	2004 - 2014
Norway	2005 - 2014
Qatar	2008 - 2014
Russia	2011 - 2014
United Kingdom	2010 - 2014
United States	2006 - 2014

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

The Corporation incurred $42 million in interest expense on income tax reserves in 2014. For 2013, the Corporation's net interest expense was a credit of $207 million, reflecting the effect of credits from the favorable resolution of prior year tax positions. The Corporation incurred $46 million in interest expense in 2012. The related interest payable balances were $205 million and $156 million at December 31, 2014, and 2013, respectively.

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $3,223 million in 2014, $886 million in 2013, and $2,832 million in 2012. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2014 - Revenue							
Sales to third parties	9,453	2,841	4,608	1,943	4,383	1,374	24,602
Transfers	5,554	5,417	5,206	14,884	7,534	1,553	40,148
	15,007	8,258	9,814	16,827	11,917	2,927	64,750
Production costs excluding taxes	4,637	4,251	3,117	2,248	1,568	583	16,404
Exploration expenses	231	363	274	427	287	87	1,669
Depreciation and depletion	4,877	1,193	1,929	3,387	1,242	454	13,082
Taxes other than income	1,116	160	412	1,539	1,542	399	5,168
Related income tax	1,208	524	2,954	5,515	4,882	435	15,518
Results of producing activities for consolidated subsidiaries	2,938	1,767	1,128	3,711	2,396	969	12,909
Equity Companies							
2014 - Revenue							
Sales to third parties	1,239	-	4,923	-	20,028	-	26,190
Transfers	924	-	63	-	685	-	1,672
	2,163	-	4,986	-	20,713	-	27,862
Production costs excluding taxes	620	-	602	-	548	-	1,770
Exploration expenses	61	-	22	-	219	-	302
Depreciation and depletion	253	-	195	-	383	-	831
Taxes other than income	57	-	2,650	-	5,184	-	7,891
Related income tax	-	-	553	-	5,099	-	5,652
Results of producing activities for equity companies	1,172	-	964	-	9,280	-	11,416
Total results of operations	4,110	1,767	2,092	3,711	11,676	969	24,325

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2013 - Revenue							
Sales to third parties	8,371	2,252	5,649	3,079	5,427	730	25,508
Transfers	6,505	5,666	5,654	15,738	8,936	1,405	43,904
	14,876	7,918	11,303	18,817	14,363	2,135	69,412
Production costs excluding taxes	4,191	3,965	2,859	2,396	1,763	654	15,828
Exploration expenses	394	386	245	288	571	92	1,976
Depreciation and depletion	4,926	989	1,881	3,269	1,680	334	13,079
Taxes other than income	1,566	94	474	1,583	1,794	427	5,938
Related income tax	1,788	542	4,124	6,841	5,709	202	19,206
Results of producing activities for consolidated subsidiaries	2,011	1,942	1,720	4,440	2,846	426	13,385
Equity Companies							
2013 - Revenue							
Sales to third parties	1,320	-	6,768	-	21,463	-	29,551
Transfers	1,034	-	64	-	6,091	-	7,189
	2,354	-	6,832	-	27,554	-	36,740
Production costs excluding taxes	551	-	459	-	660	-	1,670
Exploration expenses	19	-	15	-	426	-	460
Depreciation and depletion	207	-	169	-	955	-	1,331
Taxes other than income	51	-	3,992	-	7,352	-	11,395
Related income tax	-	-	832	-	8,482	-	9,314
Results of producing activities for equity companies	1,526	-	1,365	-	9,679	-	12,570
Total results of operations	3,537	1,942	3,085	4,440	12,525	426	25,955
Consolidated Subsidiaries							
2012 - Revenue							
Sales to third parties	6,977	1,804	5,835	3,672	6,536	1,275	26,099
Transfers	6,996	5,457	6,366	16,905	9,241	932	45,897
	13,973	7,261	12,201	20,577	15,777	2,207	71,996
Production costs excluding taxes	4,044	3,079	2,443	2,395	1,606	488	14,055
Exploration expenses	391	292	274	234	513	136	1,840
Depreciation and depletion	4,862	848	1,559	2,879	1,785	264	12,197
Taxes other than income	1,963	89	513	1,702	2,248	446	6,961
Related income tax	1,561	720	5,413	8,091	6,616	281	22,682
Results of producing activities for consolidated subsidiaries	1,152	2,233	1,999	5,276	3,009	592	14,261
Equity Companies							
2012 - Revenue							
Sales to third parties	1,284	-	6,380	-	20,017	-	27,681
Transfers	1,108	-	67	-	5,693	-	6,868
	2,392	-	6,447	-	25,710	-	34,549
Production costs excluding taxes	467	-	369	-	484	-	1,320
Exploration expenses	9	-	17	-	-	-	26
Depreciation and depletion	176	-	152	-	676	-	1,004
Taxes other than income	42	-	3,569	-	6,658	-	10,269
Related income tax	-	-	894	-	8,234	-	9,128
Results of producing activities for equity companies	1,698	-	1,446	-	9,658	-	12,802
Total results of operations	2,850	2,233	3,445	5,276	12,667	592	27,063

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $12,856 million less at year-end 2014 and $13,667 million less at year-end 2013 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2014							
Property (acreage) costs - Proved	14,664	2,598	161	876	1,660	808	20,767
- Unproved	24,062	4,824	74	615	601	136	30,312
Total property costs	38,726	7,422	235	1,491	2,261	944	51,079
Producing assets	79,138	32,635	39,996	44,700	30,219	10,051	236,739
Incomplete construction	7,051	15,344	2,114	6,075	10,163	4,621	45,368
Total capitalized costs	124,915	55,401	42,345	52,266	42,643	15,616	333,186
Accumulated depreciation and depletion	43,031	15,197	32,608	27,995	17,273	4,630	140,734
Net capitalized costs for consolidated subsidiaries	81,884	40,204	9,737	24,271	25,370	10,986	192,452
Equity Companies							
As of December 31, 2014							
Property (acreage) costs - Proved	78	-	4	-	-	-	82
- Unproved	35	-	-	-	59	-	94
Total property costs	113	-	4	-	59	-	176
Producing assets	5,538	-	5,309	-	8,500	-	19,347
Incomplete construction	473	-	251	-	2,972	-	3,696
Total capitalized costs	6,124	-	5,564	-	11,531	-	23,219
Accumulated depreciation and depletion	1,872	-	4,205	-	5,095	-	11,172
Net capitalized costs for equity companies	4,252	-	1,359	-	6,436	-	12,047
Consolidated Subsidiaries							
As of December 31, 2013							
Property (acreage) costs - Proved	13,881	3,595	188	874	1,620	863	21,021
- Unproved	23,945	5,390	61	583	701	146	30,826
Total property costs	37,826	8,985	249	1,457	2,321	1,009	51,847
Producing assets	74,743	34,487	44,161	40,424	30,082	7,973	231,870
Incomplete construction	5,640	11,811	2,219	5,913	8,387	4,194	38,164
Total capitalized costs	118,209	55,283	46,629	47,794	40,790	13,176	321,881
Accumulated depreciation and depletion	39,505	16,827	35,108	24,570	17,455	4,529	137,994
Net capitalized costs for consolidated subsidiaries	78,704	38,456	11,521	23,224	23,335	8,647	183,887
Equity Companies							
As of December 31, 2013							
Property (acreage) costs - Proved	77	-	5	-	-	-	82
- Unproved	40	-	-	-	17	-	57
Total property costs	117	-	5	-	17	-	139
Producing assets	5,206	-	6,039	-	8,397	-	19,642
Incomplete construction	416	-	201	-	1,452	-	2,069
Total capitalized costs	5,739	-	6,245	-	9,866	-	21,850
Accumulated depreciation and depletion	1,646	-	4,778	-	4,706	-	11,130
Net capitalized costs for equity companies	4,093	-	1,467	-	5,160	-	10,720

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2014 were $29,115 million, down $4,508 million from 2013, due primarily to lower property acquisition costs and development costs. In 2013 costs were $33,623 million, up $2,477 million from 2012, due primarily to higher property acquisition costs partially offset by lower exploration costs. Total equity company costs incurred in 2014 were $2,677 million, up $335 million from 2013, due primarily to exploration costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
During 2014								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	80	-	-	-	41	-	121
	- Unproved	1,253	3	19	34	-	-	1,309
Exploration costs		319	453	458	628	467	121	2,446
Development costs		7,540	6,877	1,390	4,255	3,321	1,856	25,239
Total costs incurred for consolidated subsidiaries		9,192	7,333	1,867	4,917	3,829	1,977	29,115
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	42	-	42
Exploration costs		17	-	45	-	964	-	1,026
Development costs		490	-	233	-	886	-	1,609
Total costs incurred for equity companies		507	-	278	-	1,892	-	2,677
During 2013								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	93	67	-	-	47	-	207
	- Unproved	533	4,270	-	153	-	4	4,960
Exploration costs		557	485	277	361	598	111	2,389
Development costs		6,919	8,527	2,117	3,278	3,493	1,733	26,067
Total costs incurred for consolidated subsidiaries		8,102	13,349	2,394	3,792	4,138	1,848	33,623
Equity Companies								
Property acquisition costs	- Proved	2	-	-	-	-	-	2
	- Unproved	-	-	-	-	17	-	17
Exploration costs		60	-	29	-	494	-	583
Development costs		720	-	192	-	828	-	1,740
Total costs incurred for equity companies		782	-	221	-	1,339	-	2,342
During 2012								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	192	2	95	-	43	-	332
	- Unproved	1,717	74	24	15	-	31	1,861
Exploration costs		601	405	454	520	554	248	2,782
Development costs		7,172	7,601	2,637	3,081	3,347	2,333	26,171
Total costs incurred for consolidated subsidiaries		9,682	8,082	3,210	3,616	3,944	2,612	31,146
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	14	-	-	-	-	-	14
Exploration costs		45	-	34	-	-	-	79
Development costs		504	-	156	-	651	-	1,311
Total costs incurred for equity companies		563	-	190	-	651	-	1,404

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2012, 2013, and 2014.

The definitions used are in accordance with the Securities and Exchange Commission's Rule 4-10 (a) of Regulation S-X.

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 – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. In some cases, substantial new investments in additional wells and related facilities will be required to recover these proved reserves.

In accordance with the Securities and Exchange Commission's rules, the year-end reserves volumes as well as the reserves change categories shown in the following tables were calculated using average prices during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow.

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 average prices and year-end costs that are used in the estimation of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity.

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

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves that we report for these types of arrangements typically vary inversely with oil and gas price changes. As oil and gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2014 that were associated with production sharing contract arrangements was 11 percent of liquids, 9 percent of natural gas and 10 percent on an oil-equivalent basis (gas converted to oil-equivalent at 6 billion cubic feet = 1 million barrels).

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Net proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Crude oil and natural gas liquids and natural gas production quantities shown are the net volumes withdrawn from ExxonMobil's oil and gas reserves. The natural gas quantities differ from the quantities of gas delivered for sale by the producing function as reported in the Operating Summary due to volumes consumed or flared and inventory changes.

The changes, between 2013 year-end proved reserves and 2014 year-end proved reserves, primarily reflect the revisions, extensions and discoveries in Canada and the United States.

Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	Total
	(millions of barrels)										
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2012	1,660	118	317	1,463	1,721	170	5,449	905	3,106	653	10,113
Revisions	25	33	14	20	(10)	5	87	3	265	(29)	326
Improved recovery	6	-	-	-	1	-	7	-	-	-	7
Purchases	163	-	20	-	-	-	183	36	-	-	219
Sales	(15)	(1)	(8)	(58)	-	-	(82)	(4)	-	-	(86)
Extensions/discoveries	166	138	8	41	9	-	362	164	234	-	760
Production	(100)	(18)	(62)	(173)	(117)	(12)	(482)	(73)	(45)	(25)	(625)
December 31, 2012	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599	10,714
Proportional interest in proved reserves of equity companies											
January 1, 2012	348	-	29	-	1,255	-	1,632	483	-	-	2,115
Revisions	(2)	-	1	-	131	-	130	15	-	-	145
Improved recovery	16	-	-	-	-	-	16	-	-	-	16
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(22)	-	(2)	-	(126)	-	(150)	(24)	-	-	(174)
December 31, 2012	340	-	28	-	1,260	-	1,628	474	-	-	2,102
Total liquids proved reserves at December 31, 2012	2,245	270	317	1,293	2,864	163	7,152	1,505	3,560	599	12,816
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2013	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599	10,714
Revisions	21	20	13	13	411	3	481	(1)	124	4	608
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	15	15	-	-	-	-	30	27	-	-	57
Sales	(18)	-	-	-	-	-	(18)	(6)	-	-	(24)
Extensions/discoveries	188	-	-	52	262	-	502	39	-	-	541
Production	(103)	(21)	(57)	(165)	(114)	(11)	(471)	(67)	(54)	(24)	(616)
December 31, 2013	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	11,280
Proportional interest in proved reserves of equity companies											
January 1, 2013	340	-	28	-	1,260	-	1,628	474	-	-	2,102
Revisions	12	-	2	-	21	-	35	8	-	-	43
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(22)	-	(2)	-	(136)	-	(160)	(26)	-	-	(186)
December 31, 2013	330	-	28	-	1,145	-	1,503	456	-	-	1,959
Total liquids proved reserves at December 31, 2013	2,338	284	273	1,193	3,308	155	7,551	1,479	3,630	579	13,239

(See footnote on next page)

Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves (continued)

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	Total
	(millions of barrels)										
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2014	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	11,280
Revisions	37	23	9	42	42	-	153	59	669	(23)	858
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	42	-	-	-	-	-	42	11	-	-	53
Sales	(24)	(11)	-	-	(1)	-	(36)	(14)	-	-	(50)
Extensions/discoveries	156	5	-	38	35	-	234	79	-	-	313
Production	(111)	(19)	(55)	(171)	(107)	(14)	(477)	(66)	(66)	(22)	(631)
December 31, 2014	2,108	282	199	1,102	2,132	141	5,964	1,092	4,233	534	11,823
Proportional interest in proved reserves of equity companies											
January 1, 2014	330	-	28	-	1,145	-	1,503	456	-	-	1,959
Revisions	19	-	1	-	41	-	61	5	-	-	66
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	1	-	-	-	-	-	1	-	-	-	1
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	-	-	-	1
Production	(23)	-	(2)	-	(86)	-	(111)	(26)	-	-	(137)
December 31, 2014	328	-	27	-	1,100	-	1,455	435	-	-	1,890
Total liquids proved reserves at December 31, 2014	2,436	282	226	1,102	3,232	141	7,419	1,527	4,233	534	13,713

(1) Includes total proved reserves attributable to Imperial Oil Limited of 9 million barrels in 2012, 11 million barrels in 2013 and 8 million barrels in 2014, as well as proved developed reserves of 9 million barrels in 2012, 9 million barrels in 2013 and 5 million barrels in 2014, and in addition, proved undeveloped reserves of 2 million barrels in 2013 and 3 million in 2014, in which there is a 30.4 percent noncontrolling interest.

Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves (continued)

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ South Amer. *(2)*	Canada/ South Amer. *(3)*	Total
	(millions of barrels)									
Proved developed reserves, as of December 31, 2012										
Consolidated subsidiaries	1,489	124	268	1,004	1,080	116	4,081	543	599	5,223
Equity companies	264	-	28	-	1,423	-	1,715	-	-	1,715
Proved undeveloped reserves, as of December 31, 2012										
Consolidated subsidiaries	921	163	77	497	682	134	2,474	3,017	-	5,491
Equity companies	84	-	-	-	303	-	387	-	-	387
Total liquids proved reserves at December 31, 2012	2,758	287	373	1,501	3,488	250	8,657	3,560	599	12,816
Proved developed reserves, as of December 31, 2013										
Consolidated subsidiaries	1,469	126	249	945	1,663	105	4,557	1,810	579	6,946
Equity companies	268	-	27	-	1,292	-	1,587	-	-	1,587
Proved undeveloped reserves, as of December 31, 2013										
Consolidated subsidiaries	1,068	177	51	449	638	131	2,514	1,820	-	4,334
Equity companies	77	-	1	-	294	-	372	-	-	372
Total liquids proved reserves at December 31, 2013	2,882	303	328	1,394	3,887	236	9,030	3,630	579	13,239
Proved developed reserves, as of December 31, 2014										
Consolidated subsidiaries	1,502	111	205	894	1,615	112	4,439	2,122	534	7,095
Equity companies	269	-	26	-	1,188	-	1,483	-	-	1,483
Proved undeveloped reserves, as of December 31, 2014										
Consolidated subsidiaries	1,234	190	42	401	651	99	2,617	2,111	-	4,728
Equity companies	75	-	1	-	331	-	407	-	-	407
Total liquids proved reserves at December 31, 2014	3,080	301	274	1,295	3,785	211	8,946 *(4)*	4,233	534	13,713

(1) Includes total proved reserves attributable to Imperial Oil Limited of 53 million barrels in 2012, 62 million barrels in 2013 and 46 million barrels in 2014, as well as proved developed reserves of 52 million barrels in 2012, 55 million barrels in 2013 and 36 million barrels in 2014, and in addition, proved undeveloped reserves of 1 million barrels in 2012, 7 million barrels in 2013 and 10 million barrels in 2014, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 2,841 million barrels in 2012, 2,867 million barrels in 2013 and 3,274 million barrels in 2014, as well as proved developed reserves of 543 million barrels in 2012, 1,417 million barrels in 2013 and 1,635 million barrels in 2014, and in addition, proved undeveloped reserves of 2,298 million barrels in 2012, 1,450 million barrels in 2013 and 1,639 million barrels in 2014, in which there is a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 599 million barrels in 2012, 579 million barrels in 2013 and 534 million barrels in 2014, as well as proved developed reserves of 599 million barrels in 2012, 579 million barrels in 2013 and 534 million barrels in 2014, in which there is a 30.4 percent noncontrolling interest.

(4) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2014 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent Total All Products (2)
	United States	Canada/ South Amer. (1)	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2012	26,254	835	3,586	982	6,471	7,247	45,375	17,676
Revisions	(2,888)	168	168	2	(106)	465	(2,191)	(39)
Improved recovery	-	-	-	-	-	-	-	7
Purchases	503	-	6	-	-	-	509	304
Sales	(181)	(20)	(140)	(12)	-	-	(353)	(145)
Extensions/discoveries	4,045	95	184	-	59	-	4,383	1,490
Production	(1,518)	(153)	(555)	(43)	(579)	(144)	(2,992)	(1,124)
December 31, 2012	26,215	925	3,249	929	5,845	7,568	44,731	18,169
Proportional interest in proved reserves of equity companies								
January 1, 2012	112	-	10,169	-	20,566	-	30,847	7,256
Revisions	49	-	17	-	252	-	318	198
Improved recovery	-	-	-	-	-	-	-	16
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(6)	-	(651)	-	(1,148)	-	(1,805)	(475)
December 31, 2012	155	-	9,535	-	19,670	-	29,360	6,995
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,164
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2013	26,215	925	3,249	929	5,845	7,568	44,731	18,169
Revisions	79	(56)	61	(22)	364	86	512	693
Improved recovery	-	-	-	-	-	-	-	-
Purchases	153	522	-	-	-	-	675	170
Sales	(106)	(8)	-	-	-	-	(114)	(43)
Extensions/discoveries	1,083	2	-	-	14	-	1,099	724
Production	(1,404)	(150)	(500)	(40)	(489)	(139)	(2,722)	(1,069)
December 31, 2013	26,020	1,235	2,810	867	5,734	7,515	44,181	18,644
Proportional interest in proved reserves of equity companies								
January 1, 2013	155	-	9,535	-	19,670	-	29,360	6,995
Revisions	135	-	58	-	9	-	202	77
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	8	-	-	-	9	2
Production	(10)	-	(717)	-	(1,165)	-	(1,892)	(502)
December 31, 2013	281	-	8,884	-	18,514	-	27,679	6,572
Total proved reserves at December 31, 2013	26,301	1,235	11,694	867	24,248	7,515	71,860	25,216

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent Total All Products *(2)*
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2014	26,020	1,235	2,810	867	5,734	7,515	44,181	18,644
Revisions	49	80	49	(21)	173	(38)	292	906
Improved recovery	-	-	-	-	-	-	-	-
Purchases	60	-	-	-	-	-	60	63
Sales	(314)	(48)	-	-	(3)	-	(365)	(111)
Extensions/discoveries	1,518	91	-	7	4	-	1,620	583
Production	(1,346)	(132)	(476)	(42)	(448)	(201)	(2,645)	(1,072)
December 31, 2014	25,987	1,226	2,383	811	5,460	7,276	43,143	19,013
Proportional interest in proved reserves of equity companies								
January 1, 2014	281	-	8,884	-	18,514	-	27,679	6,572
Revisions	5	-	117	-	110	-	232	105
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	1
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	1
Production	(15)	-	(583)	-	(1,119)	-	(1,717)	(423)
December 31, 2014	272	-	8,418	-	17,505	-	26,195	6,256
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269

(1) Includes total proved reserves attributable to Imperial Oil Limited of 488 billion cubic feet in 2012, 678 billion cubic feet in 2013 and 627 billion cubic feet in 2014, as well as proved developed reserves of 374 billion cubic feet in 2012, 368 billion cubic feet in 2013 and 300 billion cubic feet in 2014, and in addition, proved undeveloped reserves of 114 billion cubic feet in 2012, 310 billion cubic feet in 2013 and 327 billion cubic feet in 2014, in which there is a 30.4 percent noncontrolling interest.

(2) Natural gas is converted to oil-equivalent basis at six million cubic feet per one thousand barrels.

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent Total All Products *(2)*
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2012								
Consolidated subsidiaries	14,471	670	2,526	814	5,150	1,012	24,643	9,330
Equity companies	126	-	7,057	-	18,431	-	25,614	5,984
Proved undeveloped reserves, as of December 31, 2012								
Consolidated subsidiaries	11,744	255	723	115	695	6,556	20,088	8,839
Equity companies	29	-	2,478	-	1,239	-	3,746	1,011
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,164
Proved developed reserves, as of December 31, 2013								
Consolidated subsidiaries	14,655	664	2,189	779	5,241	969	24,497	11,029
Equity companies	197	-	6,852	-	17,288	-	24,337	5,643
Proved undeveloped reserves, as of December 31, 2013								
Consolidated subsidiaries	11,365	571	621	88	493	6,546	19,684	7,615
Equity companies	84	-	2,032	-	1,226	-	3,342	929
Total proved reserves at December 31, 2013	26,301	1,235	11,694	867	24,248	7,515	71,860	25,216
Proved developed reserves, as of December 31, 2014								
Consolidated subsidiaries	14,169	615	1,870	764	5,031	2,179	24,628	11,199
Equity companies	194	-	6,484	-	16,305	-	22,983	5,314
Proved undeveloped reserves, as of December 31, 2014								
Consolidated subsidiaries	11,818	611	513	47	429	5,097	18,515	7,814
Equity companies	78	-	1,934	-	1,200	-	3,212	942
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269

(See footnotes on previous page)

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	250,382	293,910	66,769	160,261	192,491	104,334	1,068,147
Future production costs	109,325	101,299	17,277	33,398	42,816	26,132	330,247
Future development costs	37,504	44,518	16,505	13,363	13,083	11,435	136,408
Future income tax expenses	43,772	34,692	23,252	63,246	75,261	21,405	261,628
Future net cash flows	59,781	113,401	9,735	50,254	61,331	45,362	339,864
Effect of discounting net cash flows at 10%	36,578	82,629	2,097	18,091	35,310	27,610	202,315
Discounted future net cash flows	23,203	30,772	7,638	32,163	26,021	17,752	137,549
Equity Companies							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	36,043	-	93,563	-	348,026	-	477,632
Future production costs	7,040	-	64,988	-	112,980	-	185,008
Future development costs	3,708	-	2,569	-	10,780	-	17,057
Future income tax expenses	-	-	9,937	-	78,539	-	88,476
Future net cash flows	25,295	-	16,069	-	145,727	-	187,091
Effect of discounting net cash flows at 10%	14,741	-	8,133	-	76,979	-	99,853
Discounted future net cash flows	10,554	-	7,936	-	68,748	-	87,238
Total consolidated and equity interests in standardized measure of discounted future net cash flows	33,757	30,772	15,574	32,163	94,769	17,752	224,787

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $24,690 million in 2012, in which there is a 30.4 percent noncontrolling interest.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	276,051	293,377	58,235	146,407	245,482	87,808	1,107,360
Future production costs	113,571	106,884	18,053	30,960	57,328	22,507	349,303
Future development costs	40,702	43,102	15,215	14,300	10,666	10,191	134,176
Future income tax expenses	50,144	31,901	17,186	53,766	117,989	16,953	287,939
Future net cash flows	71,634	111,490	7,781	47,381	59,499	38,157	335,942
Effect of discounting net cash flows at 10%	42,336	78,700	1,278	18,406	34,878	21,266	196,864
Discounted future net cash flows	29,298	32,790	6,503	28,975	24,621	16,891	139,078
Equity Companies							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	34,957	-	82,539	-	324,666	-	442,162
Future production costs	8,231	-	60,518	-	107,656	-	176,405
Future development costs	3,675	-	2,994	-	8,756	-	15,425
Future income tax expenses	-	-	7,237	-	70,887	-	78,124
Future net cash flows	23,051	-	11,790	-	137,367	-	172,208
Effect of discounting net cash flows at 10%	12,994	-	5,549	-	72,798	-	91,341
Discounted future net cash flows	10,057	-	6,241	-	64,569	-	80,867
Total consolidated and equity interests in standardized measure of discounted future net cash flows	39,355	32,790	12,744	28,975	89,190	16,891	219,945
Consolidated Subsidiaries							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	283,767	354,223	42,882	125,125	224,885	78,365	1,109,247
Future production costs	116,929	140,368	14,358	27,917	57,562	20,467	377,601
Future development costs	42,276	48,525	13,000	14,603	12,591	8,956	139,951
Future income tax expenses	49,807	36,787	10,651	44,977	102,581	15,050	259,853
Future net cash flows	74,755	128,543	4,873	37,628	52,151	33,892	331,842
Effect of discounting net cash flows at 10%	44,101	87,799	(52)	13,831	30,173	17,326	193,178
Discounted future net cash flows	30,654	40,744	4,925	23,797	21,978	16,566	138,664
Equity Companies							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	31,924	-	71,031	-	286,124	-	389,079
Future production costs	8,895	-	50,826	-	99,193	-	158,914
Future development costs	3,386	-	2,761	-	11,260	-	17,407
Future income tax expenses	-	-	6,374	-	59,409	-	65,783
Future net cash flows	19,643	-	11,070	-	116,262	-	146,975
Effect of discounting net cash flows at 10%	10,970	-	5,534	-	61,550	-	78,054
Discounted future net cash flows	8,673	-	5,536	-	54,712	-	68,921
Total consolidated and equity interests in standardized measure of discounted future net cash flows	39,327	40,744	10,461	23,797	76,690	16,566	207,585

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $25,160 million in 2013 and $30,189 million in 2014, in which there is a 30.4 percent noncontrolling interest.

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

Consolidated and Equity Interests	**2012**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,804
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	7,952	531	8,483
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(51,752)	(23,022)	(74,774)
Development costs incurred during the year	24,596	1,186	25,782
Net change in prices, lifting and development costs	(31,382)	5,656	(25,726)
Revisions of previous reserves estimates	3,876	7,018	10,894
Accretion of discount	19,676	8,846	28,522
Net change in income taxes	12,339	463	12,802
Total change in the standardized measure during the year	(14,695)	678	(14,017)
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,787

Consolidated and Equity Interests	**2013**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,787
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	11,928	48	11,976
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(48,742)	(23,757)	(72,499)
Development costs incurred during the year	24,821	1,389	26,210
Net change in prices, lifting and development costs	(32,423)	(5,296)	(37,719)
Revisions of previous reserves estimates	24,353	4,960	29,313
Accretion of discount	20,596	9,830	30,426
Net change in income taxes	996	6,455	7,451
Total change in the standardized measure during the year	1,529	(6,371)	(4,842)
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,945

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

Consolidated and Equity Interests (continued)	2014		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,945
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	3,497	94	3,591
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(44,446)	(18,366)	(62,812)
Development costs incurred during the year	24,189	1,453	25,642
Net change in prices, lifting and development costs	(50,672)	(13,165)	(63,837)
Revisions of previous reserves estimates	35,072	3,298	38,370
Accretion of discount	20,098	8,987	29,085
Net change in income taxes	11,848	5,753	17,601
Total change in the standardized measure during the year	(414)	(11,946)	(12,360)
Discounted future net cash flows as of December 31, 2014	138,664	68,921	207,585

OPERATING SUMMARY (unaudited)

	2014	2013	2012	2011	2010
Production of crude oil, natural gas liquids, bitumen and synthetic oil					
Net production			*(thousands of barrels daily)*		
United States	454	431	418	423	408
Canada/South America	301	280	251	252	263
Europe	184	190	207	270	335
Africa	489	469	487	508	628
Asia	624	784	772	808	730
Australia/Oceania	59	48	50	51	58
Worldwide	2,111	2,202	2,185	2,312	2,422
Natural gas production available for sale					
Net production			*(millions of cubic feet daily)*		
United States	3,404	3,545	3,822	3,917	2,596
Canada/South America	310	354	362	412	569
Europe	2,816	3,251	3,220	3,448	3,836
Africa	4	6	17	7	14
Asia	4,099	4,329	4,538	5,047	4,801
Australia/Oceania	512	351	363	331	332
Worldwide	11,145	11,836	12,322	13,162	12,148
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	3,969	4,175	4,239	4,506	4,447
Refinery throughput			*(thousands of barrels daily)*		
United States	1,809	1,819	1,816	1,784	1,753
Canada	394	426	435	430	444
Europe	1,454	1,400	1,504	1,528	1,538
Asia Pacific	628	779	998	1,180	1,249
Other Non-U.S.	191	161	261	292	269
Worldwide	4,476	4,585	5,014	5,214	5,253
Petroleum product sales *(2)*					
United States	2,655	2,609	2,569	2,530	2,511
Canada	496	464	453	455	450
Europe	1,555	1,497	1,571	1,596	1,611
Asia Pacific and other Eastern Hemisphere	1,085	1,206	1,381	1,556	1,562
Latin America	84	111	200	276	280
Worldwide	5,875	5,887	6,174	6,413	6,414
Gasoline, naphthas	2,452	2,418	2,489	2,541	2,611
Heating oils, kerosene, diesel oils	1,912	1,838	1,947	2,019	1,951
Aviation fuels	423	462	473	492	476
Heavy fuels	390	431	515	588	603
Specialty petroleum products	698	738	750	773	773
Worldwide	5,875	5,887	6,174	6,413	6,414
Chemical prime product sales *(3)*			*(thousands of metric tons)*		
United States	9,528	9,679	9,381	9,250	9,815
Non-U.S.	14,707	14,384	14,776	15,756	16,076
Worldwide	24,235	24,063	24,157	25,006	25,891

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

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

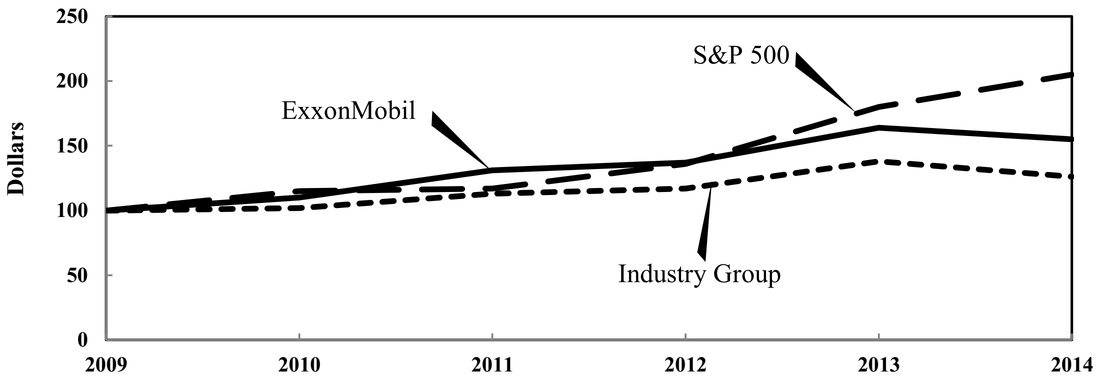
(2) Petroleum product sales data reported net of purchases/sales contracts with the same counterparty.

(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.

STOCK PERFORMANCE GRAPHS (unaudited)

Annual total returns to ExxonMobil shareholders were 5 percent in 2012, 20 percent in 2013, and -6 percent in 2014. Total returns mean share price increase plus dividends paid, with dividends reinvested. The graphs below show the relative investment performance of ExxonMobil common stock, the S&P 500, and an industry competitor group over the last five and 10 years. The industry competitor group consists of four other international integrated oil companies: BP, Chevron, Royal Dutch Shell, and Total.

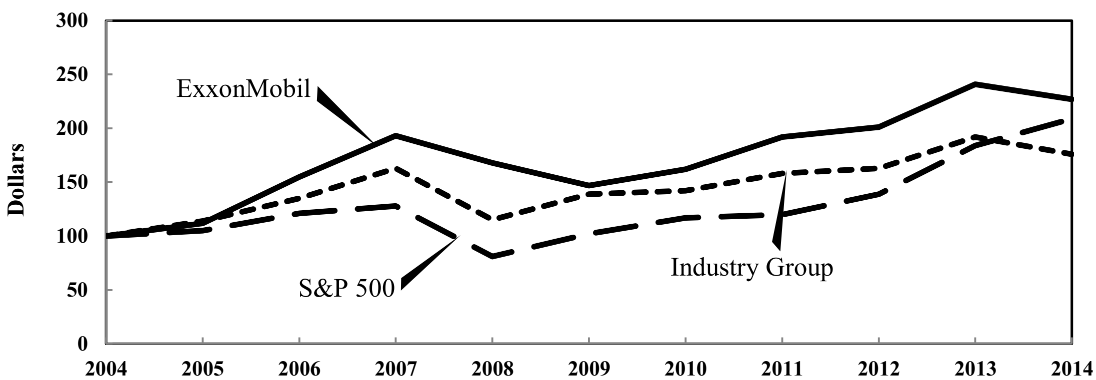
FIVE-YEAR CUMULATIVE TOTAL RETURNS
Value of $100 Invested at Year-End 2009



Fiscal Years Ended December 31

ExxonMobil	100	110	131	137	164	155
S&P 500	100	115	117	136	180	205
Industry Group	100	102	113	117	138	126

TEN-YEAR CUMULATIVE TOTAL RETURNS
Value of $100 Invested at Year-End 2004



Fiscal Years Ended December 31

ExxonMobil	100	112	155	193	168	147	162	192	201	241	227
S&P 500	100	105	121	128	81	102	117	120	139	184	209
Industry Group	100	114	135	163	115	139	142	158	163	192	176

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