ExxonMobil

2011

Financial Statements and Supplemental Information

For the Fiscal Year Ended December 31, 2011

FINANCIAL STATEMENTS AND SUPPLEMENTAL INFORMATION

For the fiscal year ended December 31, 2011

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BUSINESS PROFILE

Financial	Earnings After Income Taxes 2011	Earnings After Income Taxes 2010	Average Capital Employed 2011	Average Capital Employed 2010	Return on Average Capital Employed 2011	Return on Average Capital Employed 2010	Capital and Exploration Expenditures 2011	Capital and Exploration Expenditures 2010
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	$ 5,096	$ 4,272	$ 54,994	$ 34,969	9.3	12.2	$10,741	$ 6,349
Non-U.S.	29,343	19,825	74,813	68,318	39.2	29.0	22,350	20,970
Total	$34,439	$24,097	$129,807	$103,287	26.5	23.3	$33,091	$27,319
Downstream								
United States	$ 2,268	$ 770	$ 5,340	$ 6,154	42.5	12.5	$ 518	$ 982
Non-U.S.	2,191	2,797	18,048	17,976	12.1	15.6	1,602	1,523
Total	$ 4,459	$ 3,567	$ 23,388	$ 24,130	19.1	14.8	$ 2,120	$ 2,505
Chemical								
United States	$ 2,215	$ 2,422	$ 4,791	$ 4,566	46.2	53.0	$ 290	$ 279
Non-U.S.	2,168	2,491	15,007	14,114	14.4	17.6	1,160	1,936
Total	$ 4,383	$ 4,913	$ 19,798	$ 18,680	22.1	26.3	$ 1,450	$ 2,215
Corporate and financing	(2,221)	(2,117)	(2,272)	(880)	–	–	105	187
Total	$41,060	$30,460	$170,721	$145,217	24.2	21.7	$36,766	$32,226

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

Operating	2011	2010		2011	2010
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	423	408	United States	1,784	1,753
Non-U.S.	1,889	2,014	Non-U.S.	3,430	3,500
Total	2,312	2,422	Total	5,214	5,253
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales		
United States	3,917	2,596	United States	2,530	2,511
Non-U.S.	9,245	9,552	Non-U.S.	3,883	3,903
Total	13,162	12,148	Total	6,413	6,414
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	
Oil-equivalent production *(1)*	4,506	4,447	Chemical prime product sales		
			United States	9,250	9,815
			Non-U.S.	15,756	16,076
			Total	25,006	25,891

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

FINANCIAL SUMMARY

	2011	2010	2009	2008	2007
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	$467,029	$370,125	$301,500	$459,579	$390,328
Earnings					
Upstream	$ 34,439	$ 24,097	$ 17,107	$ 35,402	$ 26,497
Downstream	4,459	3,567	1,781	8,151	9,573
Chemical	4,383	4,913	2,309	2,957	4,563
Corporate and financing	(2,221)	(2,117)	(1,917)	(1,290)	(23)
Net income attributable to ExxonMobil	$ 41,060	$ 30,460	$ 19,280	$ 45,220	$ 40,610
Earnings per common share	$ 8.43	$ 6.24	$ 3.99	$ 8.70	$ 7.31
Earnings per common share – assuming dilution	$ 8.42	$ 6.22	$ 3.98	$ 8.66	$ 7.26
Cash dividends per common share	$ 1.85	$ 1.74	$ 1.66	$ 1.55	$ 1.37
Earnings to average ExxonMobil share of equity (percent)	27.3	23.7	17.3	38.5	34.5
Working capital	$ (4,542)	$ (3,649)	$ 3,174	$ 23,166	$ 27,651
Ratio of current assets to current liabilities (times)	0.94	0.94	1.06	1.47	1.47
Additions to property, plant and equipment	$ 33,638	$ 74,156	$ 22,491	$ 19,318	$ 15,387
Property, plant and equipment, less allowances	$214,664	$199,548	$139,116	$121,346	$120,869
Total assets	$331,052	$302,510	$233,323	$228,052	$242,082
Exploration expenses, including dry holes	$ 2,081	$ 2,144	$ 2,021	$ 1,451	$ 1,469
Research and development costs	$ 1,044	$ 1,012	$ 1,050	$ 847	$ 814
Long-term debt	$ 9,322	$ 12,227	$ 7,129	$ 7,025	$ 7,183
Total debt	$ 17,033	$ 15,014	$ 9,605	$ 9,425	$ 9,566
Fixed-charge coverage ratio (times)	53.2	42.2	25.8	54.6	51.6
Debt to capital (percent)	9.6	9.0	7.7	7.4	7.1
Net debt to capital (percent) *(2)*	2.6	4.5	(1.0)	(23.0)	(24.0)
ExxonMobil share of equity at year-end	$154,396	$146,839	$110,569	$112,965	$121,762
ExxonMobil share of equity per common share	$ 32.61	$ 29.48	$ 23.39	$ 22.70	$ 22.62
Weighted average number of common shares outstanding (millions)	4,870	4,885	4,832	5,194	5,557
Number of regular employees at year-end (thousands) *(3)*	82.1	83.6	80.7	79.9	80.8
CORS employees not included above (thousands) *(4)*	17.0	20.1	22.0	24.8	26.3

(1) Sales and other operating revenue includes sales-based taxes of $33,503 million for 2011, $28,547 million for 2010, $25,936 million for 2009, $34,508 million for 2008 and $31,728 million for 2007.

(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	2011	2010	2009
		(millions of dollars)	
Net cash provided by operating activities	$55,345	$48,413	$28,438
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	11,133	3,261	1,545
Cash flow from operations and asset sales	$66,478	$51,674	$29,983

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	2011	2010	2009
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	$331,052	$302,510	$233,323
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(69,794)	(59,846)	(49,585)
Total long-term liabilities excluding long-term debt	(83,481)	(74,971)	(58,741)
Noncontrolling interests share of assets and liabilities	(7,314)	(6,532)	(5,642)
Add ExxonMobil share of debt-financed equity company net assets	4,943	4,875	5,043
Total capital employed	$175,406	$166,036	$124,398
Total corporate sources: debt and equity perspective			
Notes and loans payable	$ 7,711	$ 2,787	$ 2,476
Long-term debt	9,322	12,227	7,129
ExxonMobil share of equity	154,396	146,839	110,569
Less noncontrolling interests share of total debt	(966)	(692)	(819)
Add ExxonMobil share of equity company debt	4,943	4,875	5,043
Total capital employed	$175,406	$166,036	$124,398

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	2011	2010	2009
		(millions of dollars)	
Net income attributable to ExxonMobil	$ 41,060	$ 30,460	$ 19,280
Financing costs (after tax)			
Gross third-party debt	(153)	(803)	(303)
ExxonMobil share of equity companies	(219)	(333)	(285)
All other financing costs – net	116	35	(483)
Total financing costs	(256)	(1,101)	(1,071)
Earnings excluding financing costs	$ 41,316	$ 31,561	$ 20,351
Average capital employed	$170,721	$145,217	$125,050
Return on average capital employed – corporate total	24.2%	21.7%	16.3%

QUARTERLY INFORMATION

	2011					2010				
	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	2,399	2,351	2,249	2,250	2,312	2,414	2,325	2,421	2,526	2,422
Refinery throughput	5,180	5,193	5,232	5,250	5,214	5,156	5,192	5,364	5,298	5,253
Petroleum product sales	6,267	6,331	6,558	6,493	6,413	6,195	6,304	6,595	6,555	6,414
Natural gas production					*(millions of cubic feet daily)*					
available for sale	14,525	12,267	12,197	13,677	13,162	11,689	10,025	12,192	14,652	12,148
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(1)*	4,820	4,396	4,282	4,530	4,506	4,362	3,996	4,453	4,968	4,447
					(thousands of metric tons)					
Chemical prime product sales	6,322	6,181	6,232	6,271	25,006	6,488	6,496	6,558	6,349	25,891
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(2)*	$109,251	121,394	120,475	115,909	467,029	$87,037	89,693	92,353	101,042	370,125
Gross profit *(3)*	$ 35,473	37,744	37,121	34,306	144,644	$28,537	29,482	30,652	32,943	121,614
Net income attributable to ExxonMobil	$ 10,650	10,680	10,330	9,400	41,060	$ 6,300	7,560	7,350	9,250	30,460
Per share data					*(dollars per share)*					
Earnings per common share *(4)*	$ 2.14	2.19	2.13	1.97	8.43	$ 1.33	1.61	1.44	1.86	6.24
Earnings per common share – assuming dilution *(4)*	$ 2.14	2.18	2.13	1.97	8.42	$ 1.33	1.60	1.44	1.85	6.22
Dividends per common share	$ 0.44	0.47	0.47	0.47	1.85	$ 0.42	0.44	0.44	0.44	1.74
Common stock prices										
High	$ 88.23	88.13	85.41	85.63	88.23	$ 70.60	70.00	62.99	73.69	73.69
Low	$ 73.64	76.72	67.03	69.21	67.03	$ 63.56	56.92	55.94	61.80	55.94

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

(2) Includes amounts for sales-based taxes.

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

(4) 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 488,846 registered shareholders of ExxonMobil common stock at December 31, 2011. At January 31, 2012, the registered shareholders of ExxonMobil common stock numbered 486,416.

On January 25, 2012, the Corporation declared a $0.47 dividend per common share, payable March 9, 2012.

FUNCTIONAL EARNINGS	2011	2010	2009
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	$ 5,096	$ 4,272	$ 2,893
Non-U.S.	29,343	19,825	14,214
Downstream			
United States	2,268	770	(153)
Non-U.S.	2,191	2,797	1,934
Chemical			
United States	2,215	2,422	769
Non-U.S.	2,168	2,491	1,540
Corporate and financing	(2,221)	(2,117)	(1,917)
Net income attributable to ExxonMobil	$41,060	$30,460	$19,280
Earnings per common share	$ 8.43	$ 6.24	$ 3.99
Earnings per common share – assuming dilution	$ 8.42	$ 6.22	$ 3.98
Special item included in earnings			
Corporate and financing			
Valdez litigation	$ –	$ –	$ (140)

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, special items, 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 2011 Form10-K.

OVERVIEW

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

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new energy supplies. While commodity prices are volatile on a short-term basis and depend on supply and demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Prices for crude oil, natural gas and refined products are based on corporate plan assumptions developed annually by major region and are utilized for investment evaluation purposes. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2040, the world's population is projected to grow to approximately 8.7 billion people, or about 1.9 billion more than in 2010. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. Expanding prosperity across a growing global population is expected to coincide with an increase in primary energy demand of about 30 percent by 2040 versus 2010, even with substantial efficiency gains around the world. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organization for Economic Cooperation and Development).

As economic progress drives demand higher, increasing penetration of energy-efficient and lower-emission fuels, technologies and practices are expected to contribute to significantly lower levels of energy consumption and emissions per unit of economic output over time. Efficiency gains will result from anticipated improvements in the transportation and power generation sectors, driven by the introduction of new technologies, as well as many other improvements that span the residential, commercial and industrial sectors.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by nearly 45 percent from 2010 to 2040. The global growth in transportation demand is likely to account for approximately 75 percent of the growth in liquids demand over this period. Nearly all the world's transportation fleets are likely to continue to run on liquid fuels because they provide a large quantity of energy in small volumes, making them easy to transport and widely available.

Demand for electricity around the world is estimated to increase approximately 80 percent by 2040, led by growth in developing countries. Consistent with this projection, power generation will 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 gain the most market share. Coal is likely to retain the leading share of power generation fuels in 2040, albeit at a much lower share than in 2010 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 wind, are likely to grow significantly over the period.

Liquid fuels provide the largest share of energy supply today due to their broad-based availability, affordability and ease of transport to meet consumer needs. By 2040, global demand for liquids is expected to grow to approximately 112 million barrels of oil-equivalent per day, an increase of more than 25 percent from 2010. Global demand for liquid fuels will be met by a wide variety of sources. Conventional crude and condensate production is expected to remain relatively flat through 2040. However, growth is expected from a wide variety of sources, including deep-water resources, oil sands, tight oil, 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 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 60 percent by 2040 compared to 2010, with demand increases in major regions around the world requiring new sources of supply. We expect that a significant growth in supplies of unconventional gas – the natural gas found in shale and other rock formations that was once considered uneconomic to produce – will help meet these needs. By 2040, unconventional gas is likely to account for about 30 percent of global gas supplies, up from 10 percent in 2010. Growing natural gas demand is likely to also stimulate significant growth in the worldwide liquefied natural gas (LNG) market, which is expected to reach 15 percent of global gas demand by 2040.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas by approximately 2025. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to less than 20 percent. Nuclear power is projected to grow significantly, albeit at a slower pace than otherwise expected in the aftermath of the Fukushima incident in Japan following the earthquake and tsunami in March 2011. Total renewable energy is likely to reach close to 15 percent of total energy by 2040, including biomass, hydro and geothermal at a combined share of about 11 percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 500 percent from 2010 to 2040, reaching a combined share of approximately 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 2011-2035 will be close to $20 trillion (measured in 2010 dollars) or close to $780 billion per year on average.

International accords and underlying regional and national regulations for greenhouse gas reduction 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 Energy Outlook, which is used for assessing the business environment and in its investment evaluations.

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

Upstream

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

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix of its production volumes between now and 2016. Oil and natural gas output from North America is expected to increase over the next five years based on current capital activity plans. Currently, this growth area accounts for 30 percent of the Corporation's production. By 2016, it is expected to generate about 35 percent of total volumes. The remainder of the Corporation's production is expected to include contributions from both established operations and new projects around the globe.

In addition to an evolving geographic mix, we expect there will also be continued change in the type of opportunities from which volumes are produced. Production from diverse resource types utilizing specialized technologies such as arctic technology, deepwater drilling and production systems, heavy oil and oil sands recovery processes, unconventional gas and oil production and LNG is expected to grow from about 45 percent to around 50 percent of the Corporation's output between now and 2016. 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 2011 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 period 2012-2016. However, actual volumes will vary from year to year due to the timing of individual project start-ups and other capital activities, operational outages, reservoir performance, performance of enhanced oil recovery projects, regulatory changes, asset sales, weather events, price effects under production sharing contracts and other factors described in Item 1A. Risk Factors of ExxonMobil's 2011 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.

Downstream

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

ExxonMobil has an ownership interest in 36 refineries, located in 21 countries, with distillation capacity of 6.2 million barrels per day and lubricant basestock manufacturing capacity of 131 thousand barrels per day. ExxonMobil's fuels and lubes marketing business portfolios include operations around the world, with multiple channels to market serving a globally diverse customer base. Our world-class brands, including *Exxon*, *Mobil* and *Esso*, are well-known.

The downstream industry environment remains challenging. Although demand for refined products has improved from the lower levels in 2009 due to the global economic recession, we expect the challenging business environment to continue, reflecting the increase in global refining capacity and regulatory related policies. Over the prior 20-year period, inflation-adjusted refining margins have been flat.

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, refinery operations, import/export balances, currency fluctuations, seasonal demand, weather and political climate.

ExxonMobil's long-term outlook is that refining margins will remain weak as competition in the industry remains intense and, in the near term, new capacity additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A. Risk Factors of ExxonMobil's 2011 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.

In the retail fuels marketing business, competition continues to cause inflation-adjusted margins to decline. In 2011, ExxonMobil progressed the transition of the direct served (i.e., dealer, company-operated) retail network in the U.S. to a more capital-efficient branded distributor model. This transition was announced in 2008 and is expected to be complete in 2012.

Our Lubricants and Specialties business continues to grow. ExxonMobil is a market leader in high-value synthetic lubricants, and we continue to grow our business in key markets such as China, India and Russia at rates considerably faster than industry.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. In 2011, we announced divestments of our Downstream businesses in Argentina, Uruguay, Paraguay, Central America, Malaysia, and Switzerland. In January 2012, we also announced the restructuring of our holdings in Japan which is disclosed in Note 20. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. These investments capitalize on the Corporation's world-class scale and integration, industry leading efficiency, leading-edge technology and respected brands, enabling ExxonMobil to take advantage of attractive emerging growth opportunities around the globe. In 2011, the company completed construction of new units and modification of existing facilities at the Sriracha, Thailand, refinery to produce lower sulfur diesel and gasoline to meet upcoming product specifications in Thailand. At the Jurong/PAC refinery in Singapore, plans are under way to build a new diesel hydrotreater, which will add capacity of more than 2 million gallons per day to meet increasing demand in the Asia Pacific region. Additionally, construction of a lower sulfur fuels project has begun at the joint Saudi Aramco and ExxonMobil SAMREF Refinery in Yanbu, Saudi Arabia. The project will include new gasoline and expanded diesel hydrotreating and sulfur recovery equipment, and completion is expected by the end of 2013. We are also expanding our Singapore and China lube oil blending plants to support future demand growth in these emerging markets.

Chemical

Worldwide petrochemical demand grew modestly in 2011. In North America, unconventional natural gas continued to provide advantaged ethane feedstock for steam crackers and a favorable margin environment for integrated chemical producers. Margins in Asia Pacific remained low, with new supply capacity outpacing demand. Specialty products overall saw firm global demand and margins.

ExxonMobil benefited from continued operational excellence and a balanced portfolio of products. In addition to being a worldwide supplier of commodity petrochemical products, ExxonMobil Chemical also has a number of less-cyclical Specialties business lines, which delivered strong results in 2011. Chemical's competitive advantages are due to its business mix, broad geographic coverage, investment and cost discipline, integration with refineries or upstream gas processing facilities, superior feedstock management, leading proprietary technology and product application expertise.

REVIEW OF 2011 AND 2010 RESULTS

	2011	2010	2009
		(millions of dollars)	
Earnings (U.S. GAAP)	$41,060	$30,460	$19,280

2011

Earnings in 2011 of $41,060 million increased $10,600 million from 2010. Earnings for 2011 did not include any special items.

2010

Earnings in 2010 of $30,460 million increased $11,180 million from 2009. Earnings for 2010 did not include any special items.

Upstream

	2011	2010	2009
		(millions of dollars)	
Upstream			
United States	$ 5,096	$ 4,272	$ 2,893
Non-U.S.	29,343	19,825	14,214
Total	$34,439	$24,097	$17,107

2011

Upstream earnings were $34,439 million, up $10,342 million from 2010. Higher crude oil and natural gas realizations increased earnings by $10.6 billion, while volume and production mix effects decreased earnings by $2.5 billion. All other items increased earnings by $2.2 billion, driven by higher gains on asset sales of $2.7 billion, partly offset by increased operating activity. On an oil-equivalent basis, production was up 1 percent compared to 2010. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was up 4 percent. Liquids production of 2,312 kbd (thousands of barrels per day) decreased 110 kbd from 2010. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was in line with 2010, as higher volumes from Qatar, the U.S., and Iraq offset field decline. Natural gas production of 13,162 mcfd (millions of cubic feet per day) increased 1,014 mcfd from 2010, driven by additional U.S. unconventional gas volumes and project ramp-ups in Qatar. Earnings from U.S. Upstream operations for 2011 were $5,096 million, an increase of $824 million. Earnings outside the U.S. were $29,343 million, up $9,518 million.

2010

Upstream earnings were $24,097 million, up $6,990 million from 2009. Higher realizations increased earnings approximately $6.5 billion. Higher volumes increased earnings by $1.2 billion, while all other items, including higher operating costs, decreased earnings by $690 million. On an oil-equivalent basis, production was up 13 percent compared to 2009. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was up 14 percent. Liquids production of 2,422 kbd increased 35 kbd compared with 2009. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production increased 2 percent from 2009, as project ramp-ups in Qatar were offset by net field decline. Natural gas production of 12,148 mcfd increased 2,875 mcfd from 2009, driven by higher volumes from Qatar projects and additional U.S. unconventional gas volumes. Earnings from U.S. Upstream operations for 2010 were $4,272 million, an increase of $1,379 million from 2009. Non-U.S. Upstream earnings were $19,825 million, up $5,611 million from 2009.

Downstream

	2011	2010	2009
	(millions of dollars)		
Downstream			
United States	$2,268	$ 770	$ (153)
Non-U.S.	2,191	2,797	1,934
Total	$4,459	$3,567	$1,781

2011

Downstream earnings of $4,459 million increased $892 million from 2010. Margins, mainly refining, increased earnings by $800 million. Volume and mix effects improved earnings by $630 million. All other items, primarily the absence of favorable tax effects and higher expenses, decreased earnings by $540 million. Petroleum product sales of 6,413 kbd were in line with 2010. U.S. Downstream earnings were $2,268 million, up $1,498 million from 2010. Non-U.S. Downstream earnings were $2,191 million, $606 million lower than last year.

2010

Downstream earnings of $3,567 million were $1,786 million higher than 2009. Higher industry refining margins increased earnings by $1.2 billion. Positive volume and mix effects increased earnings by $420 million, while all other items, including lower operating expenses, increased earnings by $210 million. Petroleum product sales of 6,414 kbd decreased 14 kbd. U.S. Downstream earnings were $770 million, up $923 million from 2009. Non-U.S. Downstream earnings were $2,797 million, $863 million higher than 2009.

Chemical

	2011	2010	2009
	(millions of dollars)		
Chemical			
United States	$2,215	$2,422	$ 769
Non-U.S.	2,168	2,491	1,540
Total	$4,383	$4,913	$2,309

2011

Chemical earnings of $4,383 million were down $530 million from 2010. Stronger margins increased earnings by $260 million, while lower volumes reduced earnings by $180 million. Other items, including unfavorable tax effects and higher planned maintenance expense, decreased earnings by $610 million. Prime product sales of 25,006 kt (thousands of metric tons) were down 885 kt from 2010. Prime product sales are total chemical product sales, including ExxonMobil's share of equity-company volumes and finished product transfers to the Downstream business. U.S. Chemical earnings were $2,215 million, down $207 million from 2010. Non-U.S. Chemical earnings were $2,168 million, $323 million lower than last year.

2010

Chemical earnings were a record $4,913 million, up $2,604 million from 2009. Improved margins increased earnings by $2.0 billion while higher volumes increased earnings $380 million. Prime product sales of 25,891 kt were up 1,066 kt from 2009. U.S. Chemical earnings of $2,422 million increased $1,653 million. Non-U.S. Chemical earnings of $2,491 million increased $951 million.

Corporate and Financing

	2011	2010	2009
	(millions of dollars)		
Corporate and financing	$(2,221)	$(2,117)	$(1,917)

2011

Corporate and financing expenses were $2,221 million, up $104 million from 2010.

2010

Corporate and financing expenses were $2,117 million, up $200 million from 2009 mainly due to a tax charge related to the U.S.

health care legislation during the first quarter of 2010 and financing activities, partially offset by the absence of a 2009 charge for interest related to the Valdez punitive damages award.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2011	2010	2009
	(millions of dollars)		
Net cash provided by/(used in)			
Operating activities	$ 55,345	$ 48,413	$ 28,438
Investing activities	(22,165)	(24,204)	(22,419)
Financing activities	(28,256)	(26,924)	(27,283)
Effect of exchange rate changes	(85)	(153)	520
Increase/(decrease) in cash and cash equivalents	$ 4,839	$ (2,868)	$(20,744)
	(Dec. 31)		
Cash and cash equivalents	$ 12,664	$ 7,825	$ 10,693
Cash and cash equivalents – restricted	404	628	–
Total cash and cash equivalents	$ 13,068	$ 8,453	$ 10,693

Total cash and cash equivalents were $13.1 billion at the end of 2011, $4.6 billion higher than the prior year. Higher earnings, proceeds associated with asset sales, including a $3.6 billion deposit for a potential asset sale, and a net debt increase in contrast with prior year debt repurchases were partially offset by a higher level of purchases of ExxonMobil shares and a higher level of capital spending. Included in total cash and cash equivalents at year-end 2011 was $0.4 billion of restricted cash.

Total cash and cash equivalents were $8.5 billion at the end of 2010, $2.2 billion lower than the prior year. Higher earnings and reduced share purchases were offset by a higher level of capital spending and increased level of debt repurchases. Included in total cash and cash equivalents at year-end 2010 was $0.6 billion of restricted cash. For additional details, see the Consolidated Statement of Cash Flows.

Although the Corporation has access to significant capacity of long-term and short-term liquidity, internally generated funds cover the majority of its financial requirements. Cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns.

To support cash flows in future periods the Corporation will need to continually find and develop new fields, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of production at plateau rates, it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Averaged over all the Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline at an average of approximately 3 percent per year over the next few years. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. Furthermore, the Corporation's net interest in production for individual fields can vary with price and contractual terms.

The Corporation has long been successful at offsetting the effects of natural field decline through disciplined investments in quality opportunities and project execution. Over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a variety of risks including project start-up timing, operational outages, reservoir performance, crude oil and natural gas prices, weather events, and regulatory changes. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. Risk Factors of ExxonMobil's 2011 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 2011 were $36.8 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment profile of about $37 billion per year for the next several years. Actual spending could vary depending on the progress of individual projects. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments. The purchase and sale of oil and gas properties have not had a significant impact on the amount or timing of cash flows from operating activities.

Cash Flow from Operating Activities

2011

Cash provided by operating activities totaled $55.3 billion in 2011, $6.9 billion higher than 2010. The major source of funds was net income including noncontrolling interests of $42.2 billion, adjusted for the noncash provision of $15.6 billion for depreciation and depletion, both of which increased. Changes in operational working capital, excluding cash and debt, and the adjustment for net gains on asset sales decreased cash in 2011. Net working capital continued to be negative as total current liabilities of $77.5 billion exceeded total current assets of $73.0 billion at year-end 2011.

2010

Cash provided by operating activities totaled $48.4 billion in 2010, $20.0 billion higher than 2009. The major source of funds was net income including noncontrolling interests of $31.4 billion, adjusted for the noncash provision of $14.8 billion for depreciation and depletion, both of which increased. The net effects of changes in prices and the timing of collection of accounts receivable and of payments of accounts and other payables and of income taxes payable increased cash provided by operating activities in 2010 compared to a decrease in 2009, and resulted in net working capital of $(3.6) billion as total current liabilities of $62.6 billion exceeded total current assets of $59.0 billion at year-end 2010.

Cash Flow from Investing Activities

2011

Cash used in investment activities netted to $22.2 billion in 2011, $2.0 billion lower than 2010. Spending for property, plant and equipment of $31.0 billion increased $4.1 billion from 2010. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $11.1 billion compared to $3.3 billion in 2010. The increase primarily reflects the sale of Upstream Canadian, U.K. and other producing properties and assets, the sale of U.S. service stations, and a $3.6 billion deposit for a potential asset sale. Additional investments and advances were $2.3 billion higher in 2011.

2010

Cash used in investment activities netted to $24.2 billion in 2010, $1.8 billion higher than in 2009. Spending for property, plant and equipment of $26.9 billion increased $4.4 billion from 2009. Proceeds from the sale of subsidiaries, investments and property, plant and equipment of $3.3 billion in 2010 compared to $1.5 billion in 2009, the increase reflecting the sale of some U.S. service stations and Upstream Gulf of Mexico and other producing properties.

Cash Flow from Financing Activities

2011

Cash used in financing activities was $28.3 billion in 2011, $1.3 billion higher than 2010. Dividend payments on common shares increased to $1.85 per share from $1.74 per share and totaled $9.0 billion, a pay-out of 22 percent. Total debt increased $2.0 billion to $17.0 billion at year-end.

ExxonMobil share of equity increased $7.6 billion to $154.4 billion. The addition to equity for earnings of $41.1 billion was partially offset by reductions for distributions to ExxonMobil shareholders of $9.0 billion of dividends and $20.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. The change in the funded status of the postretirement benefits reserves in 2011 decreased equity by $4.6 billion.

During 2011, Exxon Mobil Corporation purchased 278 million shares of its common stock for the treasury at a gross cost of $22.1 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 4.9 percent from 4,979 million to 4,734 million at the end of 2011. 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.

2010

Cash used in financing activities was $26.9 billion in 2010, $0.4 billion lower than 2009. Dividend payments on common shares increased to $1.74 per share from $1.66 per share and totaled $8.5 billion, a pay-out of 28 percent. Total debt increased to $15.0 billion at year end, an increase of $5.4 billion from 2009, primarily as a result of debt assumed with the XTO merger.

ExxonMobil share of equity increased $36.3 billion to $146.8 billion. The addition to equity for earnings of $30.5 billion and the issuance of stock for the XTO merger of $24.7 billion was partially offset by reductions to equity for distributions to ExxonMobil shareholders of $8.5 billion of dividends and $11.2 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2010, Exxon Mobil Corporation issued 416 million shares for the XTO merger. Exxon Mobil Corporation purchased 199 million shares of its common stock for the treasury at a gross cost of $13.1 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding increased by 5.3 percent from 4,727 million at the end of 2009 to 4,979 million at the end of 2010. 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, 2011. 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 2012	2013-2016	2017 and Beyond	Total
		(millions of dollars)			
Long-term debt *(1)*	13	$ –	$ 2,947	$ 6,375	$ 9,322
– Due in one year *(2)*	5	3,431	–	–	3,431
Asset retirement obligations *(3)*	8	922	2,748	6,908	10,578
Pension and other postretirement obligations *(4)*	16	3,890	4,150	17,632	25,672
Operating leases *(5)*	10	2,152	4,132	1,630	7,914
Unconditional purchase obligations *(6)*	15	243	660	410	1,313
Take-or-pay obligations *(7)*		2,241	7,505	9,275	19,021
Firm capital commitments *(8)*		16,024	11,287	629	27,940

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 $4.9 billion as of December 31, 2011, because the Corporation is unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can be found in Note 18, Income, Sales-Based and Other Taxes.

Notes:

(1) *Includes capitalized lease obligations of $260 million.*

(2) *The amount due in one year is included in notes and loans payable of $7,711 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 2012 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 $1,313 million mainly pertain to pipeline throughput agreements and include $856 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 $19,021 million mainly pertain to manufacturing supply, pipeline and terminaling agreements and include $316 million of obligations to equity companies.*

(8) *Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $27.9 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $13.9 billion was associated with projects in Africa, Australia, Malaysia and Canada. The Corporation expects to fund the majority of these projects through internal cash flow.*

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2011, for guarantees relating to notes, loans and performance under contracts (Note 15). The below-mentioned guarantees are not reasonably likely to have a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

	Dec. 31, 2011		
	Equity Company Obligations*(1)*	Other Third-Party Obligations	Total
	(millions of dollars)		
Guarantees			
Debt-related	$1,546	$ 65	$1,611
Other	3,061	3,784	6,845
Total	$4,607	$3,849	$8,456

(1) ExxonMobil share.

Financial Strength

On December 31, 2011, unused credit lines for short-term financing totaled approximately $5.5 billion (Note 5).

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

	2011	2010	2009
Fixed-charge coverage ratio (times)	53.2	42.2	25.8
Debt to capital (percent)	9.6	9.0	7.7
Net debt to capital (percent)	2.6	4.5	(1.0)

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 15, 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 15 for additional information on legal proceedings and other contingencies.

CAPITAL AND EXPLORATION EXPENDITURES

	2011		2010	
	U.S.	Non-U.S	U.S.	Non-U.S.
		(millions of dollars)		
Upstream *(1)*	$10,741	$22,350	$6,349	$20,970
Downstream	518	1,602	982	1,523
Chemical	290	1,160	279	1,936
Other	105	–	187	–
Total	$11,654	$25,112	$7,797	$24,429

(1) Exploration expenses included.

Capital and exploration expenditures in 2011 were $36.8 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment profile of about $37 billion per year for the next several years. Actual spending could vary depending on the progress of individual projects.

Upstream spending of $33.1 billion in 2011 was up 21 percent from 2010, reflecting unconventional gas activities in the U.S. and continued progress on world-class projects in Australia, Canada and Papua New Guinea. The majority of expenditures are on development projects, which typically take two to four years from the time of recording proved undeveloped reserves to the start of production from those reserves. The percentage of proved developed reserves was 65 percent of total proved reserves at year-end 2011, and has been over 60 percent for the last five years, indicating that proved reserves are consistently moved from undeveloped to developed status. Capital investments in the Downstream totaled $2.1 billion in 2011, a decrease of $0.4 billion from 2010, due to completion of environmental-related refining projects, primarily in the U.S. The Chemical capital expenditures of $1.5 billion were $0.8 billion lower in 2011 as investments in Asia to meet demand growth progressed toward completion.

TAXES

	2011	2010	2009
		(millions of dollars)	
Income taxes	$ 31,051	$21,561	$15,119
Effective income tax rate	*46%*	*45%*	*47%*
Sales-based taxes	33,503	28,547	25,936
All other taxes and duties	43,544	39,127	37,571
Total	$108,098	$89,235	$78,626

2011

Income, sales based and all other taxes and duties totaled $108.1 billion in 2011, an increase of $18.9 billion or 21 percent from 2010. Income tax expense, both current and deferred, was $31.1 billion, $9.5 billion higher than 2010, reflecting higher pre-tax income in 2011. A higher share of pre-tax income from the Upstream segment in 2011 increased the effective tax rate to 46 percent compared to 45 percent in 2010. Sales-based and all other taxes and duties of $77.0 billion in 2011 increased $9.4 billion, reflecting higher prices.

2010

Income, sales-based and all other taxes and duties totaled $89.2 billion in 2010, an increase of $10.6 billion or 13 percent from 2009. Income tax expense, both current and deferred, was $21.6 billion, $6.4 billion higher than 2009, reflecting higher pre-tax income in 2010. A lower share of pre-tax income from the Upstream segment in 2010 decreased the effective tax rate to 45 percent compared to 47 percent in 2009. Sales-based and all other taxes and duties of $67.7 billion in 2010 increased $4.2 billion, reflecting higher prices.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2011	2010
	(millions of dollars)	
Capital expenditures	$1,636	$1,947
Other expenditures	3,248	2,593
Total	$4,884	$4,540

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. ExxonMobil's 2011 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $4.9 billion. The total cost for such activities is expected to remain in this range in 2012 and 2013 (with capital expenditures approximately 45 percent of the total).

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites could mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations or financial condition. Consolidated company provisions made in 2011 for environmental liabilities were $420 million ($448 million in 2010) and the balance sheet reflects accumulated liabilities of $886 million as of December 31, 2011, and $948 million as of December 31, 2010.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2011	2010	2009
Crude oil and NGL ($/barrel)	$100.79	$74.04	$57.86
Natural gas ($/kcf)	4.65	4.31	4.00

(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 $200 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide 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 are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term due to political events, OPEC actions and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the Corporation tests the viability of all of its investments over a broad range of future prices. The Corporation's assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management programs.

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

Risk Management

The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact of such changes. With respect to derivatives activities, the Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivatives described in Note 12. 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 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. Although the Corporation issues long-term debt from time to time and maintains a commercial paper program, internally generated funds are expected to cover the majority of its net near-term financial requirements. However, some joint-venture partners are dependent on the credit markets, and their funding ability may impact the development pace of joint-venture projects.

The Corporation conducts business in many foreign currencies and is subject to exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil's geographically and functionally diverse operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts to mitigate the impact of changes in currency values, and exposures related to the Corporation's limited use of the currency exchange contracts are not material.

Inflation and Other Uncertainties

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

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 integral to making investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis for calculating unit-of-production depreciation rates and for evaluating impairment.

Oil and gas reserves include both proved and unproved reserves. Proved 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 2011 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 2011 (including both consolidated and equity company reserves), and has been over 60 percent for the last five 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 costs that are used in the estimation of reserves. Revisions can also result from significant changes in development strategy or production equipment/facility capacity.

The Corporation uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method.

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

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

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

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

Accordingly, any impairment tests that the Corporation performs make use of the Corporation's price assumptions developed in the annual planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on 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 (ARO)

The Corporation incurs retirement obligations for certain assets at the time they are installed. The fair value of these obligations are recorded as liabilities on a discounted basis. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. AROs are disclosed in Note 8 to the financial statements.

Suspended Exploratory Well Costs

The Corporation carries as an asset exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalization of suspended wells as of year-end 2011 are disclosed in Note 9 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 and liabilities. Amounts representing the Corporation's percentage 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 percentage ownership. The Corporation does not invest in these companies in order to remove liabilities from its balance sheet. In fact, the Corporation has long been on record supporting an alternative accounting method that would require each investor to consolidate its percentage share of all assets and liabilities in these partially owned companies rather than only its percentage in the net equity. This method of accounting for investments in partially owned companies is not permitted by GAAP except where the investments are in the direct ownership of a share of upstream assets and liabilities. However, for purposes of calculating return on average capital employed, which is not covered by GAAP standards, the Corporation includes its share of debt of these partially-owned companies in the determination of average capital employed.

Pension Benefits

The Corporation and its affiliates sponsor over 100 defined benefit (pension) plans in about 50 countries. Pension and Other Postretirement Benefits (Note 16) provides details on pension obligations, fund assets and pension expense.

Some of these plans (primarily non-U.S.) provide pension benefits that are paid directly by their sponsoring affiliates out of corporate cash flow rather than a separate pension fund. Book reserves are established for these plans because tax conventions and regulatory practices do not encourage advance funding. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

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

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

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2011 was 7.5 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 6 percent and 9 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately $140 million before tax.

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

Litigation Contingencies

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

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 18.

Foreign Currency Translation

The method of translating the foreign currency financial statements of the Corporation's international subsidiaries into U.S. dollars is prescribed by GAAP. Under these principles, it is necessary to select the functional currency of these subsidiaries. The functional currency is the currency of the primary economic environment in which the subsidiary operates. Management selects the functional currency after evaluating this economic environment.

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* 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, 2011.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2011, as stated in their report included in the Financial Section of this report.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

pwc

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, 2011, and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corporation's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in 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 24, 2012

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2011	2010	2009
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		$467,029	$370,125	$301,500
Income from equity affiliates	6	15,289	10,677	7,143
Other income		4,111	2,419	1,943
Total revenues and other income		$486,429	$383,221	$310,586
Costs and other deductions				
Crude oil and product purchases		$266,534	$197,959	$152,806
Production and manufacturing expenses		40,268	35,792	33,027
Selling, general and administrative expenses		14,983	14,683	14,735
Depreciation and depletion		15,583	14,760	11,917
Exploration expenses, including dry holes		2,081	2,144	2,021
Interest expense		247	259	548
Sales-based taxes *(1)*	18	33,503	28,547	25,936
Other taxes and duties	18	39,973	36,118	34,819
Total costs and other deductions		$413,172	$330,262	$275,809
Income before income taxes		$ 73,257	$ 52,959	$ 34,777
Income taxes	18	31,051	21,561	15,119
Net income including noncontrolling interests		$ 42,206	$ 31,398	$ 19,658
Net income attributable to noncontrolling interests		1,146	938	378
Net income attributable to ExxonMobil		$ 41,060	$ 30,460	$ 19,280
Earnings per common share (dollars)	11	$ 8.43	$ 6.24	$ 3.99
Earnings per common share – assuming dilution (dollars)	11	$ 8.42	$ 6.22	$ 3.98

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

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2011	Dec. 31 2010
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		$ 12,664	$ 7,825
Cash and cash equivalents – restricted		404	628
Notes and accounts receivable, less estimated doubtful amounts	5	38,642	32,284
Inventories			
Crude oil, products and merchandise	3	11,665	9,852
Materials and supplies		3,359	3,124
Other current assets		6,229	5,271
Total current assets		$ 72,963	$ 58,984
Investments, advances and long-term receivables	7	34,333	35,338
Property, plant and equipment, at cost, less accumulated depreciation and depletion	8	214,664	199,548
Other assets, including intangibles, net		9,092	8,640
Total assets		$ 331,052	$ 302,510
Liabilities			
Current liabilities			
Notes and loans payable	5	$ 7,711	$ 2,787
Accounts payable and accrued liabilities	5	57,067	50,034
Income taxes payable		12,727	9,812
Total current liabilities		$ 77,505	$ 62,633
Long-term debt	13	9,322	12,227
Postretirement benefits reserves	16	24,994	19,367
Deferred income tax liabilities	18	36,618	35,150
Other long-term obligations		21,869	20,454
Total liabilities		$ 170,308	$ 149,831
Commitments and contingencies	15		
Equity			
Common stock without par value			
(9,000 million shares authorized, 8,019 million shares issued)		$ 9,512	$ 9,371
Earnings reinvested		330,939	298,899
Accumulated other comprehensive income			
Cumulative foreign exchange translation adjustment		4,168	5,011
Postretirement benefits reserves adjustment		(13,291)	(9,889)
Unrealized gain on cash flow hedges		–	55
Common stock held in treasury (3,285 million shares in 2011 and 3,040 million shares in 2010)		(176,932)	(156,608)
ExxonMobil share of equity		$ 154,396	$ 146,839
Noncontrolling interests		6,348	5,840
Total equity		160,744	152,679
Total liabilities and equity		$ 331,052	$ 302,510

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2011	2010	2009
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		$ 42,206	$ 31,398	$ 19,658
Adjustments for noncash transactions				
Depreciation and depletion		15,583	14,760	11,917
Deferred income tax charges/(credits)		142	(1,135)	–
Postretirement benefits expense in excess of/(less than) net payments		544	1,700	(1,722)
Other long-term obligation provisions in excess of/(less than) payments		(151)	160	731
Dividends received greater than/(less than) equity in current earnings of equity companies		(273)	(596)	(483)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) – Notes and accounts receivable		(7,906)	(5,863)	(3,170)
– Inventories		(2,208)	(1,148)	459
– Other current assets		222	913	132
Increase/(reduction) – Accounts and other payables		8,880	9,943	1,420
Net (gain) on asset sales	4	(2,842)	(1,401)	(488)
All other items – net		1,148	(318)	(16)
Net cash provided by operating activities		$ 55,345	$ 48,413	$ 28,438
Cash flows from investing activities				
Additions to property, plant and equipment		$(30,975)	$(26,871)	$(22,491)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	4	11,133	3,261	1,545
Decrease/(increase) in restricted cash and cash equivalents		224	(628)	–
Additional investments and advances		(3,586)	(1,239)	(2,752)
Collection of advances		1,119	1,133	724
Additions to marketable securities		(1,754)	(15)	(16)
Sales of marketable securities		1,674	155	571
Net cash used in investing activities		$(22,165)	$(24,204)	$(22,419)
Cash flows from financing activities				
Additions to long-term debt		$ 702	$ 1,143	$ 225
Reductions in long-term debt		(266)	(6,224)	(68)
Additions to short-term debt		1,063	598	1,336
Reductions in short-term debt		(1,103)	(2,436)	(1,575)
Additions/(reductions) in debt with three months or less maturity		1,561	709	(71)
Cash dividends to ExxonMobil shareholders		(9,020)	(8,498)	(8,023)
Cash dividends to noncontrolling interests		(306)	(281)	(280)
Changes in noncontrolling interests		(16)	(7)	(113)
Tax benefits related to stock-based awards		260	122	237
Common stock acquired		(22,055)	(13,093)	(19,703)
Common stock sold		924	1,043	752
Net cash used in financing activities		$(28,256)	$(26,924)	$(27,283)
Effects of exchange rate changes on cash		$ (85)	$ (153)	$ 520
Increase/(decrease) in cash and cash equivalents		$ 4,839	$ (2,868)	$(20,744)
Cash and cash equivalents at beginning of year		7,825	10,693	31,437
Cash and cash equivalents at end of year		$ 12,664	$ 7,825	$ 10,693

Non-Cash Transactions

The Corporation acquired all the outstanding equity of XTO Energy Inc. in an all-stock transaction valued at $24,659 million in 2010 (see Note 19).

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	Noncontrolling Interests	Total Equity
				(millions of dollars)			
Balance as of December 31, 2008	$5,314	$265,680	$(9,931)	$(148,098)	$112,965	$4,558	$117,523
Amortization of stock-based awards	685	–	–	–	685	–	685
Tax benefits related to stock-based awards	140	–	–	–	140	–	140
Other	(636)	–	–	–	(636)	–	(636)
Net income for the year	–	19,280	–	–	19,280	378	19,658
Dividends – common shares	–	(8,023)	–	–	(8,023)	(280)	(8,303)
Foreign exchange translation adjustment	–	–	3,256	–	3,256	373	3,629
Postretirement benefits reserves adjustment (Note 16)	–	–	(196)	–	(196)	(144)	(340)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (Note 16)	–	–	1,410	–	1,410	51	1,461
Acquisitions, at cost	–	–	–	(19,703)	(19,703)	(127)	(19,830)
Dispositions	–	–	–	1,391	1,391	14	1,405
Balance as of December 31, 2009	$5,503	$276,937	$(5,461)	$(166,410)	$110,569	$4,823	$115,392
Amortization of stock-based awards	751	–	–	–	751	–	751
Tax benefits related to stock-based awards	280	–	–	–	280	–	280
Other	(683)	–	–	–	(683)	10	(673)
Net income for the year	–	30,460	–	–	30,460	938	31,398
Dividends – common shares	–	(8,498)	–	–	(8,498)	(281)	(8,779)
Foreign exchange translation adjustment	–	–	584	–	584	450	1,034
Adjustment for foreign exchange translation loss included in net income	–	–	25	–	25	–	25
Postretirement benefits reserves adjustment (Note 16)	–	–	(1,014)	–	(1,014)	(147)	(1,161)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (Note 16)	–	–	988	–	988	52	1,040
Change in fair value of cash flow hedges	–	–	184	–	184	–	184
Realized (gain)/loss from settled cash flow hedges included in net income	–	–	(129)	–	(129)	–	(129)
Acquisitions, at cost	–	–	–	(13,093)	(13,093)	(5)	(13,098)
Issued for XTO merger	3,520	–	–	21,139	24,659	–	24,659
Other dispositions	–	–	–	1,756	1,756	–	1,756
Balance as of December 31, 2010	$9,371	$298,899	$(4,823)	$(156,608)	$146,839	$5,840	$152,679
Amortization of stock-based awards	742	–	–	–	742	–	742
Tax benefits related to stock-based awards	202	–	–	–	202	–	202
Other	(803)	–	–	–	(803)	(5)	(808)
Net income for the year	–	41,060	–	–	41,060	1,146	42,206
Dividends – common shares	–	(9,020)	–	–	(9,020)	(306)	(9,326)
Foreign exchange translation adjustment	–	–	(843)	–	(843)	(24)	(867)
Postretirement benefits reserves adjustment (Note 16)	–	–	(4,557)	–	(4,557)	(350)	(4,907)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (Note 16)	–	–	1,155	–	1,155	62	1,217
Change in fair value of cash flow hedges	–	–	28	–	28	–	28
Realized (gain)/loss from settled cash flow hedges included in net income	–	–	(83)	–	(83)	–	(83)
Acquisitions, at cost	–	–	–	(22,055)	(22,055)	(15)	(22,070)
Dispositions	–	–	–	1,731	1,731	–	1,731
Balance as of December 31, 2011	$9,512	$330,939	$(9,123)	$(176,932)	$154,396	$6,348	$160,744

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2008	8,019	(3,043)	4,976
Acquisitions	–	(277)	(277)
Dispositions	–	28	28
Balance as of December 31, 2009	8,019	(3,292)	4,727
Acquisitions	–	(199)	(199)
Issued for XTO merger	–	416	416
Other dispositions	–	35	35
Balance as of December 31, 2010	8,019	(3,040)	4,979
Acquisitions	–	(278)	(278)
Dispositions	–	33	33
Balance as of December 31, 2011	8,019	(3,285)	4,734

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2011	2010	2009
		(millions of dollars)	
Net income including noncontrolling interests	$42,206	$31,398	$19,658
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(867)	1,034	3,629
Adjustment for foreign exchange translation loss included in net income	–	25	–
Postretirement benefits reserves adjustment (excluding amortization)	(4,907)	(1,161)	(340)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs	1,217	1,040	1,461
Change in fair value of cash flow hedges	28	184	–
Realized (gain)/ loss from settled cash flow hedges included in net income	(83)	(129)	–
Comprehensive income including noncontrolling interests	37,594	32,391	24,408
Comprehensive income attributable to noncontrolling interests	834	1,293	658
Comprehensive income attributable to ExxonMobil	$36,760	$31,098	$23,750

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

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Exxon Mobil Corporation.

The Corporation's principal business is energy, involving the worldwide exploration, production, transportation and sale of crude oil and natural gas (Upstream) and the manufacture, transportation and sale of petroleum products (Downstream). The Corporation is also a major worldwide manufacturer and marketer of petrochemicals (Chemical) and participates in electric power generation (Upstream).

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2011 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 and liabilities.

Amounts representing the Corporation's percentage interest in the underlying net assets of 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 the Consolidated Statement of Changes in Equity.

Evidence of loss in value that might indicate impairment of investments in companies accounted for on the equity method is assessed to determine if such evidence represents a loss in value of the Corporation's investment that is other than temporary. Examples of key indicators include a history of operating losses, a negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If evidence of an other than temporary loss in fair value below carrying amount is determined, an impairment is recognized. In the absence of market prices for the investment, discounted cash flows are used to assess fair value.

Revenue Recognition. The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments. 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.

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

The Corporation uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method.

The Corporation carries as an asset exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred.

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

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil, gas and other minerals that are estimated to be recoverable from existing facilities using current operating methods.

Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

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

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

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

Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. Impairments are measured by the amount the carrying value exceeds the fair value.

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 no uncertainty about the recovery of costs applicable to any interest retained or where there is no substantial obligation for future performance by the Corporation.

Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties and projected cash expenditures are not discounted.

Foreign Currency Translation. The Corporation selects the functional reporting currency for its international subsidiaries based on the currency of the primary economic environment in which each subsidiary operates.

Downstream and Chemical operations primarily use the local currency. However, the U.S. dollar is used in countries with a history of high inflation (primarily in Latin America) and Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations which are relatively self-contained and integrated within a particular country, such as Canada, the United Kingdom, Norway and continental Europe, use the local currency. Some Upstream operations, primarily in Asia 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 market price of the restricted shares at the date of grant and is recognized in the income statement over the requisite service period of each award. See Note 14, Incentive Program, for further details.

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2011 that had a material impact on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development costs totaled $1,044 million in 2011, $1,012 million in 2010 and $1,050 million in 2009.

Net income included before-tax aggregate foreign exchange transaction losses of $184 million and $251 million, and gains of $54 million in 2011, 2010 and 2009, respectively.

In 2011, 2010 and 2009, net income included gains of $292 million, $317 million and $207 million, respectively, attributable to the combined effects of LIFO inventory accumulations and draw-downs. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $25.6 billion and $21.3 billion at December 31, 2011, and 2010, respectively.

Crude oil, products and merchandise as of year-end 2011 and 2010 consist of the following:

	2011	2010
	(billions of dollars)	
Petroleum products	$ 4.1	$3.5
Crude oil	4.8	3.8
Chemical products	2.3	2.1
Gas/other	0.5	0.5
Total	$11.7	$9.9

4. Cash Flow Information

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

The "Net (gain) on asset sales" in net cash provided by operating activities on the Consolidated Statement of Cash Flows includes before-tax gains from the sale of some Upstream Canadian, U.K. and other producing properties and assets, and the sale of U.S. service stations in 2011; from the sale of some Upstream Gulf of Mexico and other producing properties, the sale of U.S. service stations and other Downstream assets and investments and the formation of a Chemical joint venture in 2010; and from the sale of Downstream assets and investments and producing properties in the Upstream in 2009. These gains are reported in "Other income" on the Consolidated Statement of Income.

Included in "Proceeds associated with sales of subsidiaries, property, plant, and equipment, and sales and returns of investments" in 2011 is a $3.6 billion deposit for a potential asset sale.

	2011	2010	2009
		(millions of dollars)	
Cash payments for interest	$ 557	$ 703	$ 820
Cash payments for income taxes	$27,254	$18,941	$15,427

5. Additional Working Capital Information

	Dec. 31 2011	Dec. 31 2010
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $128 million and $152 million	$30,044	$25,439
Other, less reserves of $39 million and $34 million	8,598	6,845
Total	$38,642	$32,284
Notes and loans payable		
Bank loans	$ 1,237	$ 532
Commercial paper	2,281	1,346
Long-term debt due within one year	3,431	345
Other	762	564
Total	$ 7,711	$ 2,787
Accounts payable and accrued liabilities		
Trade payables	$33,969	$30,780
Payables to equity companies	5,553	5,450
Accrued taxes other than income taxes	7,123	6,778
Other	10,422	7,026
Total	$57,067	$50,034

On December 31, 2011, unused credit lines for short-term financing totaled approximately $5.5 billion. Of this total, $2.8 billion support commercial paper programs under terms negotiated when drawn. The weighted-average interest rate on short-term borrowings outstanding at December 31, 2011, and 2010, was 1.9 percent and 1.2 percent, respectively.

6. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These companies are primarily engaged in crude production, natural gas marketing and refining operations in North America; natural gas production, natural gas distribution and downstream operations in Europe; crude production in Kazakhstan; and liquefied natural gas (LNG) operations in Qatar. Also included are several power generation, refining, petrochemical manufacturing and chemical ventures. The Corporation's ownership in these ventures is in the form of shares in corporate joint ventures as well as interests in partnerships. The share of total equity company revenues from sales to ExxonMobil consolidated companies was 19 percent, 18 percent and 19 percent in the years 2011, 2010 and 2009, respectively.

	2011		2010		2009	
Equity Company Financial Summary	Total	ExxonMobil Share	Total	ExxonMobil Share	Total	ExxonMobil Share
			(millions of dollars)			
Total revenues	$204,635	$65,147	$153,020	$48,355	$112,153	$36,570
Income before income taxes	$ 68,908	$20,892	$ 48,075	$14,735	$ 28,472	$ 9,632
Income taxes	19,812	5,603	13,962	4,058	7,775	2,489
Income from equity affiliates	$ 49,096	$15,289	$ 34,113	$10,677	$ 20,697	$ 7,143
Current assets	$ 52,879	$17,317	$ 48,573	$15,860	$ 37,376	$12,843
Long-term assets	96,908	30,833	90,646	29,805	88,153	27,983
Total assets	$149,787	$48,150	$139,219	$45,665	$125,529	$40,826
Current liabilities	$ 41,016	$12,454	$ 33,160	$10,260	$ 24,854	$ 8,085
Long-term liabilities	62,472	18,728	59,596	17,976	57,384	16,999
Net assets	$ 46,299	$16,968	$ 46,463	$17,429	$ 43,291	$15,742

A list of significant equity companies as of December 31, 2011, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
BEB Erdgas und Erdoel GmbH	50
Cameroon Oil Transportation Company S.A.	41
Castle Peak Power Company Limited	60
Golden Pass LNG Terminal LLC	18
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

	Percentage Ownership Interest
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
Saudi Yanbu Petrochemical Co.	50
Toray Tonen Specialty Separator Godo Kaisha	50

7. Investments, Advances and Long-Term Receivables

	Dec. 31, 2011	Dec. 31, 2010
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	$16,968	$17,429
Advances	9,740	9,286
Total equity company investments and advances	$26,708	$26,715
Companies carried at cost or less and stock investments carried at fair value	1,544	1,557
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $469 million and $292 million	6,081	7,066
Total	$34,333	$35,338

8. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	Dec. 31, 2011		Dec. 31, 2010	
	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	$283,710	$163,975	$264,136	$148,152
Downstream	67,900	28,801	68,652	30,095
Chemical	30,405	14,469	29,524	14,255
Other	11,980	7,419	11,626	7,046
Total	$393,995	$214,664	$373,938	$199,548

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 $179,331 million at the end of 2011 and $174,390 million at the end of 2010. Interest capitalized in 2011, 2010 and 2009 was $593 million, $532 million and $425 million, respectively.

Asset Retirement Obligations

The Corporation incurs retirement obligations for its upstream assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. The Corporation uses estimates, 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 (unobservable inputs) 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:

	2011	2010
	(millions of dollars)	
Beginning balance	$ 9,614	$8,473
Accretion expense and other provisions	581	563
Reduction due to property sales	(854)	(183)
Payments made	(662)	(638)
Liabilities incurred	117	1,094
Foreign currency translation	(62)	(45)
Revisions	1,844	350
Ending balance	$10,578	$9,614

9. Accounting for Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs beyond one year after the well is completed if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress is being made in assessing the reserves and the economic and operating viability of the project.

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

Change in capitalized suspended exploratory well costs:

	2011	2010	2009
		(millions of dollars)	
Balance beginning at January 1	$2,893	$2,005	$1,585
Additions pending the determination of proved reserves	310	1,103	624
Charged to expense	(213)	(104)	(51)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(149)	(136)	(200)
Other	40	25	47
Ending balance	$2,881	$2,893	$2,005
Ending balance attributed to equity companies included above	$ –	$ –	$ 9

Period end capitalized suspended exploratory well costs:

	2011	2010	2009
		(millions of dollars)	
Capitalized for a period of one year or less	$ 310	$1,103	$ 624
Capitalized for a period of between one and five years	1,922	1,294	924
Capitalized for a period of between five and ten years	409	278	220
Capitalized for a period of greater than ten years	240	218	237
Capitalized for a period greater than one year – subtotal	$2,571	$1,790	$1,381
Total	$2,881	$2,893	$2,005

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.

	2011	2010	2009
Number of projects with first capitalized well drilled in the preceding 12 months	4	9	18
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	58	59	57
Total	62	68	75

Of the 58 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2011, 26 projects have drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 32 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 32 projects, which total $1,133 million.

Country/Project	Dec. 31, 2011	Years Wells Drilled	Comment
(millions of dollars)			
Angola			
– Perpetua-Zina-Acacia	$ 15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned infrastructure.
Australia			
– East Pilchard	10	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
– SE Longtom	15	2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
Indonesia			
– 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	Declarations involving field commerciality filed with Kazakhstan government in 2008; progressing commercialization and field development studies.
Malaysia			
– Besar	18	1992 - 2010	Gas field off the east coast of Malaysia; progressing development plan.
– Other (2 projects)	8	1979 - 1995	Projects primarily awaiting capacity in existing or 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.
– Pegi	32	2009	Awaiting capacity in existing/planned infrastructure
– Other (4 projects)	13	2002	Pursuing development of several additional offshore satellite discoveries which will tie back to existing/planned production facilities.
Norway			
– Gamma	20	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
– H-North	15	2007	Discovery near existing facilities in Fram area; progressing development plans.
– Lavrans	22	1995 - 1999	Development awaiting capacity in existing Kristin production facility; evaluating development concepts for phased ullage scenarios.
– Nyk High	19	2008	Evaluating field development alternatives.
– Other (6 projects)	26	1992 - 2010	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
– Juha	28	2007	Working on development plans to tie into planned LNG facilities.
United Kingdom			
– Fram	55	2009	Progressing development and commercialization plans.
– Other (2 projects)	14	2001 - 2004	Projects primarily awaiting capacity in existing or planned infrastructure.
United States			
– Julia Unit	78	2007 - 2008	Reached agreement with the Department of Interior and Department of Justice providing for suspension of production; progressing development plans with partners.
– Point Thomson	449	1977 - 2010	Continuing discussions with government and partners on development plan.
– Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Total 2011 (32 projects)	$1,133		

10. Leased Facilities

At December 31, 2011, 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 $7,914 million as indicated in the table. Estimated related rental income from noncancelable subleases is $107 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	(millions of dollars)	
2012	$2,152	$ 18
2013	1,696	17
2014	1,219	15
2015	802	12
2016	415	10
2017 and beyond	1,630	35
Total	$7,914	$107

Net rental cost under both cancelable and noncancelable operating leases incurred during 2011, 2010 and 2009 were as follows:

	2011	2010	2009
		(millions of dollars)	
Rental cost	$4,061	$3,762	$4,426
Less sublease rental income	74	90	98
Net rental cost	$3,987	$3,672	$4,328

11. Earnings Per Share

	2011	2010	2009
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	$41,060	$30,460	$19,280
Weighted average number of common shares outstanding *(millions of shares)*	4,870	4,885	4,832
Earnings per common share *(dollars)*	$ 8.43	$ 6.24	$ 3.99
Earnings per common share – assuming dilution			
Net income attributable to ExxonMobil *(millions of dollars)*	$41,060	$30,460	$19,280
Weighted average number of common shares outstanding *(millions of shares)*	4,870	4,885	4,832
Effect of employee stock-based awards	5	12	16
Weighted average number of common shares outstanding – assuming dilution	4,875	4,897	4,848
Earnings per common share – assuming dilution *(dollars)*	$ 8.42	$ 6.22	$ 3.98
Dividends paid per common share *(dollars)*	$ 1.85	$ 1.74	$ 1.66

12. 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, including capitalized lease obligations, was $9.8 billion and $12.8 billion at December 31, 2011, and 2010, respectively, as compared to recorded book values of $9.3 billion and $12.2 billion at December 31, 2011, and 2010, respectively. The fair value hierarchy for long-term debt is primarily Level 1 (quoted prices for identical assets in active markets).

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 cash flow hedge positions acquired as a result of the XTO merger were settled by December 31, 2011, and those programs have been discontinued.

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net liability of $3 million at year-end 2011 and a net asset of $172 million at year-end 2010. Assets and liabilities associated with derivatives are predominantly recorded either in "Other current assets" or "Accounts payable and accrued liabilities."

The Corporation's fair value measurement of its derivative instruments uses primarily Level 2 inputs (derivatives that are determined by either market prices on an active market for similar assets or by prices quoted by a broker or other market-corroborated prices).

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $131 million, $221 million and $(73) million during 2011, 2010 and 2009, respectively. Income statement effects associated with derivatives are recorded either in "Sales and other operating revenue" or "Crude oil and product purchases." Of the amount stated above for 2011, cash flow hedges resulted in a before-tax gain of $136 million.

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.

13. Long-Term Debt

At December 31, 2011, long-term debt consisted of $8,855 million due in U.S. dollars and $467 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 $3,431 million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing, in each of the four years after December 31, 2012, in millions of dollars, are: 2013 – $967, 2014 – $871, 2015 – $606 and 2016 – $503. At December 31, 2011, the Corporation's unused long-term credit lines were not material.

Summarized long-term debt at year-end 2011 and 2010 are shown in the table below:

	2011	2010
	(millions of dollars)	
SeaRiver Maritime Financial Holdings, Inc. *(1)*		
Guaranteed deferred interest debentures due 2012		
– Face value net of unamortized discount plus accrued interest	$ –	$ 2,389
XTO Energy Inc. *(2)*		
7.500% senior note due 2012	–	199
5.900% senior note due 2012	–	233
6.250% senior note due 2013	185	193
4.625% senior note due 2013	145	149
5.750% senior note due 2013	346	359
4.900% senior note due 2014	260	267
5.000% senior note due 2015	138	142
5.300% senior note due 2015	255	262
5.650% senior note due 2016	222	227
6.250% senior note due 2017	513	534
5.500% senior note due 2018	402	420
6.500% senior note due 2018	506	524
6.100% senior note due 2036	203	204
6.750% senior note due 2037	317	329
6.375% senior note due 2038	241	258
Mobil Services (Bahamas) Ltd.		
Variable note due 2035 *(3)*	972	972
Variable note due 2034 *(4)*	311	311
Mobil Producing Nigeria Unlimited *(5)*		
Variable notes due 2012-2017	543	415
Esso (Thailand) Public Company Ltd. *(6)*		
Variable notes due 2012-2017	413	522
Mobil Corporation		
8.625% debentures due 2021	248	248
Industrial revenue bonds due 2012-2051 *(7)*	2,315	2,247
Other U.S. dollar obligations *(8)*	496	454
Other foreign currency obligations	31	65
Capitalized lease obligations *(9)*	260	304
Total long-term debt	$9,322	$12,227

(1) Additional information is provided for this subsidiary on the following pages.

(2) Includes premiums of $421 million.

(3) Average effective interest rate of 0.2% in 2011 and 0.3% in 2010.

(4) Average effective interest rate of 0.3% in 2011 and 0.4% in 2010.

(5) Average effective interest rate of 4.2% in 2011 and 4.6% in 2010.

(6) Average effective interest rate of 3.2% in 2011 and 1.7% in 2010.

(7) Average effective interest rate of 0.1% in 2011 and 0.2% in 2010.

(8) Average effective interest rate of 4.8% in 2011 and 4.7% in 2010.

(9) Average imputed interest rate of 8.5% in 2011 and 8.1% in 2010.

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

Exxon Mobil Corporation has fully and unconditionally guaranteed the deferred interest debentures due 2012 ($2,662 million short-term) of SeaRiver Maritime Financial Holdings, Inc., a 100-percent-owned subsidiary of Exxon Mobil Corporation.

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

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of income for 12 months ended December 31, 2011					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 17,942	$ –	$449,087	$ –	$467,029
Income from equity affiliates	39,198	(14)	15,196	(39,091)	15,289
Other income	472	–	3,639	–	4,111
Intercompany revenue	54,891	3	451,627	(506,521)	–
Total revenues and other income	112,503	(11)	919,549	(545,612)	486,429
Costs and other deductions					
Crude oil and product purchases	57,604	–	704,125	(495,195)	266,534
Production and manufacturing expenses	7,827	–	38,234	(5,793)	40,268
Selling, general and administrative expenses	2,936	–	12,748	(701)	14,983
Depreciation and depletion	1,660	–	13,923	–	15,583
Exploration expenses, including dry holes	219	–	1,862	–	2,081
Interest expense	305	274	4,512	(4,844)	247
Sales-based taxes	–	–	33,503	–	33,503
Other taxes and duties	40	–	39,933	–	39,973
Total costs and other deductions	70,591	274	848,840	(506,533)	413,172
Income before income taxes	41,912	(285)	70,709	(39,079)	73,257
Income taxes	852	(101)	30,300	–	31,051
Net income including noncontrolling interests	41,060	(184)	40,409	(39,079)	42,206
Net income attributable to noncontrolling interests	–	–	1,146	–	1,146
Net income attributable to ExxonMobil	$ 41,060	$ (184)	$ 39,263	$ (39,079)	$ 41,060

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of income for 12 months ended December 31, 2010					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$15,382	$ –	$354,743	$ –	$370,125
Income from equity affiliates	28,401	(2)	10,589	(28,311)	10,677
Other income	790	–	1,629	–	2,419
Intercompany revenue	39,433	4	332,483	(371,920)	–
Total revenues and other income	84,006	2	699,444	(400,231)	383,221
Costs and other deductions					
Crude oil and product purchases	40,788	–	518,961	(361,790)	197,959
Production and manufacturing expenses	7,627	–	33,400	(5,235)	35,792
Selling, general and administrative expenses	2,871	–	12,482	(670)	14,683
Depreciation and depletion	1,761	–	12,999	–	14,760
Exploration expenses, including dry holes	251	–	1,893	–	2,144
Interest expense	217	246	4,035	(4,239)	259
Sales-based taxes	–	–	28,547	–	28,547
Other taxes and duties	29	–	36,089	–	36,118
Total costs and other deductions	53,544	246	648,406	(371,934)	330,262
Income before income taxes	30,462	(244)	51,038	(28,297)	52,959
Income taxes	2	(90)	21,649	–	21,561
Net income including noncontrolling interests	30,460	(154)	29,389	(28,297)	31,398
Net income attributable to noncontrolling interests	–	–	938	–	938
Net income attributable to ExxonMobil	$30,460	$ (154)	$ 28,451	$ (28,297)	$ 30,460
Condensed consolidated statement of income for 12 months ended December 31, 2009					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$11,352	$ –	$290,148	$ –	$301,500
Income from equity affiliates	19,852	7	7,060	(19,776)	7,143
Other income	813	–	1,130	–	1,943
Intercompany revenue	30,889	4	271,663	(302,556)	–
Total revenues and other income	62,906	11	570,001	(322,332)	310,586
Costs and other deductions					
Crude oil and product purchases	31,419	–	411,689	(290,302)	152,806
Production and manufacturing expenses	7,811	–	30,805	(5,589)	33,027
Selling, general and administrative expenses	2,574	–	12,852	(691)	14,735
Depreciation and depletion	1,571	–	10,346	–	11,917
Exploration expenses, including dry holes	230	–	1,791	–	2,021
Interest expense	1,200	222	5,126	(6,000)	548
Sales-based taxes	–	–	25,936	–	25,936
Other taxes and duties	(29)	–	34,848	–	34,819
Total costs and other deductions	44,776	222	533,393	(302,582)	275,809
Income before income taxes	18,130	(211)	36,608	(19,750)	34,777
Income taxes	(1,150)	(81)	16,350	–	15,119
Net income including noncontrolling interests	19,280	(130)	20,258	(19,750)	19,658
Net income attributable to noncontrolling interests	–	–	378	–	378
Net income attributable to ExxonMobil	$19,280	$ (130)	$ 19,880	$ (19,750)	$ 19,280

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated balance sheet for year ended December 31, 2011					
Cash and cash equivalents	$ 1,354	$ –	$ 11,310	$ –	$ 12,664
Cash and cash equivalents – restricted	239	–	165	–	404
Notes and accounts receivable – net	2,719	–	36,569	(646)	38,642
Inventories	1,634	–	13,390	–	15,024
Other current assets	353	–	5,876	–	6,229
Total current assets	6,299	–	67,310	(646)	72,963
Investments and other assets	260,410	393	485,157	(702,535)	43,425
Property, plant and equipment – net	19,687	–	194,977	–	214,664
Intercompany receivables	17,325	2,726	543,844	(563,895)	–
Total assets	$ 303,721	$ 3,119	$1,291,288	$(1,267,076)	$ 331,052
Notes and loans payable	$ 1,851	$ 2,662	$ 3,198	$ –	$ 7,711
Accounts payable and accrued liabilities	3,117	57	53,893	–	57,067
Income taxes payable	–	2	13,371	(646)	12,727
Total current liabilities	4,968	2,721	70,462	(646)	77,505
Long-term debt	293	–	9,029	–	9,322
Postretirement benefits reserves	12,344	–	12,650	–	24,994
Deferred income tax liabilities	1,450	–	35,168	–	36,618
Other long-term liabilities	5,215	–	16,654	–	21,869
Intercompany payables	125,055	386	438,454	(563,895)	–
Total liabilities	149,325	3,107	582,417	(564,541)	170,308
Earnings reinvested	330,939	(1,032)	141,467	(140,435)	330,939
Other equity	(176,543)	1,044	561,056	(562,100)	(176,543)
ExxonMobil share of equity	154,396	12	702,523	(702,535)	154,396
Noncontrolling interests	–	–	6,348	–	6,348
Total equity	154,396	12	708,871	(702,535)	160,744
Total liabilities and equity	$ 303,721	$ 3,119	$1,291,288	$(1,267,076)	$ 331,052

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated balance sheet for year ended December 31, 2010					
Cash and cash equivalents	$ 309	$ –	$ 7,516	$ –	$ 7,825
Cash and cash equivalents – restricted	371	–	257	–	628
Notes and accounts receivable – net	2,104	–	30,346	(166)	32,284
Inventories	1,457	–	11,519	–	12,976
Other current assets	239	–	5,032	–	5,271
Total current assets	4,480	–	54,670	(166)	58,984
Investments and other assets	255,005	458	462,893	(674,378)	43,978
Property, plant and equipment – net	18,830	–	180,718	–	199,548
Intercompany receivables	18,186	2,457	528,405	(549,048)	–
Total assets	$ 296,501	$ 2,915	$1,226,686	$(1,223,592)	$ 302,510
Notes and loans payable	$ 1,042	$ 13	$ 1,732	$ –	$ 2,787
Accounts payable and accrued liabilities	2,987	–	47,047	–	50,034
Income taxes payable	–	3	9,975	(166)	9,812
Total current liabilities	4,029	16	58,754	(166)	62,633
Long-term debt	295	2,389	9,543	–	12,227
Postretirement benefits reserves	9,660	–	9,707	–	19,367
Deferred income tax liabilities	642	107	34,401	–	35,150
Other long-term liabilities	5,632	–	14,822	–	20,454
Intercompany payables	129,404	382	419,262	(549,048)	–
Total liabilities	149,662	2,894	546,489	(549,214)	149,831
Earnings reinvested	298,899	(848)	132,357	(131,509)	298,899
Other equity	(152,060)	869	542,000	(542,869)	(152,060)
ExxonMobil share of equity	146,839	21	674,357	(674,378)	146,839
Noncontrolling interests	–	–	5,840	–	5,840
Total equity	146,839	21	680,197	(674,378)	152,679
Total liabilities and equity	$ 296,501	$ 2,915	$1,226,686	$(1,223,592)	$ 302,510

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of cash flows for 12 months ended December 31, 2011					
Cash provided by/(used in) operating activities	$ 37,752	$ 63	$ 47,683	$(30,153)	$ 55,345
Cash flows from investing activities					
Additions to property, plant and equipment	(2,516)	–	(28,459)	–	(30,975)
Proceeds associated with sales of long-term assets	667	–	10,466	–	11,133
Decrease/(increase) in restricted cash and cash equivalents	132	–	92	–	224
Net intercompany investing	(4,227)	(229)	4,015	441	–
All other investing, net	(1,679)	–	(868)	–	(2,547)
Net cash provided by/(used in) investing activities	(7,623)	(229)	(14,754)	441	(22,165)
Cash flows from financing activities					
Additions to short- and long-term debt	–	–	1,765	–	1,765
Reductions in short- and long-term debt	(2)	(13)	(1,354)	–	(1,369)
Additions/(reductions) in debt with three months or less maturity	809	–	752	–	1,561
Cash dividends	(9,020)	–	(30,153)	30,153	(9,020)
Common stock acquired	(22,055)	–	–	–	(22,055)
Net intercompany financing activity	–	4	262	(266)	–
All other financing, net	1,184	175	(322)	(175)	862
Net cash provided by/(used in) financing activities	(29,084)	166	(29,050)	29,712	(28,256)
Effects of exchange rate changes on cash	–	–	(85)	–	(85)
Increase/(decrease) in cash and cash equivalents	$ 1,045	$ –	$ 3,794	$ –	$ 4,839
Condensed consolidated statement of cash flows for 12 months ended December 31, 2010					
Cash provided by/(used in) operating activities	$ 35,740	$ 63	$ 18,307	$ (5,697)	$ 48,413
Cash flows from investing activities					
Additions to property, plant and equipment	(2,922)	–	(23,949)	–	(26,871)
Proceeds associated with sales of long-term assets	1,484	–	1,777	–	3,261
Decrease/(increase) in restricted cash and cash equivalents	(371)	–	(257)	–	(628)
Net intercompany investing	(13,966)	(200)	13,813	353	–
All other investing, net	(672)	–	706	–	34
Net cash provided by/(used in) investing activities	(16,447)	(200)	(7,910)	353	(24,204)
Cash flows from financing activities					
Additions to short- and long-term debt	–	–	1,741	–	1,741
Reductions in short- and long-term debt	(3)	(13)	(8,644)	–	(8,660)
Additions/(reductions) in debt with three months or less maturity	997	–	(288)	–	709
Cash dividends	(8,498)	–	(5,697)	5,697	(8,498)
Common stock acquired	(13,093)	–	–	–	(13,093)
Net intercompany financing activity	–	–	202	(202)	–
All other financing, net	1,164	150	(286)	(151)	877
Net cash provided by/(used in) financing activities	(19,433)	137	(12,972)	5,344	(26,924)
Effects of exchange rate changes on cash	–	–	(153)	–	(153)
Increase/(decrease) in cash and cash equivalents	$ (140)	$ –	$ (2,728)	$ –	$ (2,868)

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)		
Condensed consolidated statement of cash flows for 12 months ended December 31, 2009					
Cash provided by/(used in) operating activities	$ 27,424	$ 72	$ 28,024	$(27,082)	$ 28,438
Cash flows from investing activities					
Additions to property, plant and equipment	(2,686)	–	(19,805)	–	(22,491)
Proceeds associated with sales of long-term assets	228	–	1,317	–	1,545
Decrease/(increase) in restricted cash and cash equivalents	–	–	–	–	–
Net intercompany investing	(1,826)	(209)	1,717	318	–
All other investing, net	–	–	(1,473)	–	(1,473)
Net cash provided by/(used in) investing activities	(4,284)	(209)	(18,244)	318	(22,419)
Cash flows from financing activities					
Additions to short- and long-term debt	–	–	1,561	–	1,561
Reductions in short- and long-term debt	(3)	(13)	(1,627)	–	(1,643)
Additions/(reductions) in debt with three months or less maturity	39	–	(110)	–	(71)
Cash dividends	(8,023)	–	(27,082)	27,082	(8,023)
Common stock acquired	(19,703)	–	–	–	(19,703)
Net intercompany financing activity	–	–	168	(168)	–
All other financing, net	988	150	(392)	(150)	596
Net cash provided by/(used in) financing activities	(26,702)	137	(27,482)	26,764	(27,283)
Effects of exchange rate changes on cash	–	–	520	–	520
Increase/(decrease) in cash and cash equivalents	$ (3,562)	$ –	$(17,182)	$ –	$(20,744)

14. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. 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 2011, remaining shares available for award under the 2003 Incentive Program were 133,183 thousand.

Restricted Stock. Awards totaling 10,533 thousand, 10,648 thousand (excluding XTO merger-related grants), and 10,133 thousand of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2011, 2010 and 2009, 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. These shares 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 may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares in each award vesting after three years and the remaining 50 percent vesting after seven years. 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.

Additionally, in 2010 long-term incentive awards totaling 4,206 thousand shares of restricted (nonvested) common stock, with a value of $250 million, were granted in association with the XTO merger. The majority of these awards vest over periods of up to three years after the initial grant.

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, 2011.

Restricted stock and units outstanding	2011 Shares	2011 Weighted Average Grant-Date Fair Value per Share
	(thousands)	
Issued and outstanding at January 1	47,306	$69.74
2010 award issued in 2011	10,639	$68.74
Vested	(10,628)	$64.37
Forfeited	(536)	$67.35
Issued and outstanding at December 31	46,781	$70.76

Value of restricted stock and units	2011	2010	2009
Grant price	$79.52	$66.07	$75.40
Value at date of grant:			
	(millions of dollars)		
Restricted stock and units settled in stock	$ 766	$ 672	$ 711
Merger-related granted and converted XTO awards	–	250	–
Units settled in cash	72	60	53
Total value	$ 838	$ 982	$ 764

As of December 31, 2011, there was $2,168 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 units was $793 million, $801 million and $723 million for 2011, 2010 and 2009, respectively. The income tax benefit recognized in income related to this compensation expense was $73 million, $81 million and $76 million for the same periods, respectively. The fair value of shares and units vested in 2011, 2010 and 2009 was $801 million, $718 million and $763 million, respectively. Cash payments of $46 million, $42 million and $41 million for vested restricted stock units settled in cash were made in 2011, 2010 and 2009, respectively.

Stock Options. The Corporation has not granted any stock options under the 2003 Incentive Program. In 2010, the Corporation granted 12,393 thousand of converted XTO stock options with a grant-date fair value of $182 million as a result of the XTO merger. The grant included 893 thousand of unvested options. Compensation expense for these awards is based on estimated grant-date fair values.

These stock options generally vest and become exercisable ratably over a three-year period, and may include a provision for accelerated vesting when the common stock price reaches specified levels. Some stock option tranches vest only when the common stock price reaches specified levels. As of December 31, 2011, unvested stock options of 226 thousand included 10 thousand options that vest ratably over three years and 216 thousand options that vest at a stock price of $126.80.

Changes that occurred in the Corporation's stock options in 2011 are summarized below:

	2011		
Stock options	Shares	Avg. Exercise Price	Weighted Average Remaining Contractual Term
	(thousands)		
Outstanding at January 1	29,509	$44.65	
Exercised	(23,880)	$38.81	
Forfeited	(80)	$48.01	
Outstanding at December 31	5,549	$69.76	3.0 Years
Exercisable at December 31	5,323	$68.65	3.0 Years

Compensation expense of $1 million in 2011 and $2 million in 2010 fully expensed the nonvested merger-related XTO stock options. No compensation expense was recognized for stock options in 2009 as all remaining outstanding stock options at that time were fully vested. Cash received from stock option exercises was $924 million, $1,043 million and $752 million for 2011, 2010 and 2009, respectively. The cash tax benefit realized for the options exercised was $221 million, $89 million and $164 million for 2011, 2010 and 2009, respectively. The aggregate intrinsic value of stock options exercised in 2011, 2010 and 2009 was $986 million, $539 million and $563 million, respectively. The intrinsic value for the balance of outstanding stock options at December 31, 2011, was $98 million. The intrinsic value for the balance of exercisable stock options at December 31, 2011, was $97 million.

15. Litigation and Other Contingencies

Litigation. A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Corporation does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. 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.

On June 30, 2011, a state district court jury in Baltimore County, Maryland returned a verdict against Exxon Mobil Corporation in *Allison, et al v. Exxon Mobil Corporation*, a case involving an accidental 26,000 gallon gasoline leak at a suburban Baltimore service station. The verdict included approximately $497 million in compensatory damages and approximately $1.0 billion in punitive damages in a finding that ExxonMobil fraudulently misled the plantiff-residents about the events leading up to the leak, the leak's discovery, and the nature and extent of any groundwater contamination. ExxonMobil believes the verdict is not justified by the evidence and that the amount of the compensatory award is grossly excessive and the imposition of punitive damages is improper and unconstitutional. The trial court denied a post-trial motion that ExxonMobil filed to overturn the punitive damages verdict. Following the entry of a final judgment, ExxonMobil will appeal the verdict and judgment. In a prior trial involving the same leak, the jury awarded plantiff-residents compensatory damages but decided against punitive damages. The plaintiffs did not appeal the jury's denial of punitive damages. Following an appeal by ExxonMobil of the compensatory damages award, on February 9, 2012, the Maryland Special Court of Appeals reversed in part and affirmed in part the trial court's decision on compensatory damages. The ultimate outcome of this litigation is not expected to 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, 2011, for guarantees relating to notes, loans and performance under contracts.

	Dec. 31, 2011		
	Equity Company Obligations*(1)*	Other Third-Party Obligations	Total
	(millions of dollars)		
Guarantees			
Debt-related	$1,546	$ 65	$1,611
Other	3,061	3,784	6,845
Total	$4,607	$3,849	$8,456

(1) ExxonMobil share.

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

	Payments Due by Period			
	2012	2013-2016	2017 and Beyond	Total
	(millions of dollars)			
Unconditional purchase obligations *(1)*	$243	$660	$410	$1,313

(1) Undiscounted obligations of $1,313 million mainly pertain to pipeline throughput agreements and include $856 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of $229 million, totaled $1,084 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. ExxonMobil's remaining net book investment in Cerro Negro producing assets was about $750 million at year-end 2011.

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. The ICSID arbitration proceeding is continuing and a hearing on the merits was held in February 2012. At this time, 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, Mobil Cerro Negro, Ltd. (MCN), also filed an arbitration under the rules of the International Chamber of Commerce (ICC) against PdVSA and a PdVSA affiliate, PdVSA CN, for breach of their contractual obligations under certain Cerro Negro Project agreements. On December 23, 2011, the tribunal rendered its award which found PdVSA and PdVSA CN jointly and severally liable to MCN in the amount of about $908 million. The tribunal deducted approximately $161 million of uncontested debt owed by MCN to PdVSA and PdVSA CN, leaving a balance of about $747 million. Post-award interest on this net amount was set at the New York prime rate compounded annually and running from the date of the award. The tribunal granted PdVSA and PdVSA CN a sixty-day grace period in which to comply with the award. On January 26, 2012, MCN filed a motion to confirm the award against PdVSA CN. In response to an order to show cause filed by PdVSA on January 17, 2012, the United States District Court for the Southern District of New York, on February 1, 2012, ordered the release to MCN of approximately $305 million of PdVSA CN funds previously attached in connection with the arbitration in partial satisfaction of the award. MCN received those funds on February 10, 2012. In further satisfaction of the award, PdVSA cancelled approximately $195 million in MCN bond debt on February 13, 2012. PdVSA paid MCN the balance of the monetary portion of the award on February 14, 2012.

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 have petitioned a Nigerian federal court for enforcement of the award, and NNPC has petitioned the same court to have the award set aside. Those proceedings are pending. 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.

16. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2011	2010	2011	2010	2011	2010
	(percent)					
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	5.00	5.50	4.00	4.80	5.00	5.50
Long-term rate of compensation increase	5.75	5.25	5.40	5.20	5.75	5.25
	(millions of dollars)					
Change in benefit obligation						
Benefit obligation at January 1	$15,007	$13,981	$25,722	$23,344	$7,331	$6,748
Service cost	546	468	574	480	121	101
Interest cost	792	798	1,267	1,175	393	395
Actuarial loss/(gain)	1,954	553	3,086	1,672	427	277
Benefits paid *(1) (2)*	(1,264)	(873)	(1,470)	(1,281)	(473)	(394)
Foreign exchange rate changes	–	–	(303)	169	(11)	26
Plan amendments, other	–	80	192	163	92	178
Benefit obligation at December 31	$17,035	$15,007	$29,068	$25,722	$7,880	$7,331
Accumulated benefit obligation at December 31	$14,081	$12,764	$25,480	$22,958	$ –	$ –

(1) Benefit payments for funded and unfunded plans.

(2) For 2011 and 2010, other postretirement benefits paid are net of $29 million and $15 million of Medicare subsidy receipts, respectively.

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

The measurement of the accumulated postretirement benefit obligation assumes an initial health care cost trend rate of 5.5 percent that declines to 4.5 percent by 2015. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $63 million and the postretirement benefit obligation by $696 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $49 million and the postretirement benefit obligation by $567 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2011	2010	2011	2010	2011	2010
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	$10,835	$10,277	$16,765	$15,401	$558	$514
Actual return on plan assets	505	1,235	123	1,482	–	63
Foreign exchange rate changes	–	–	(192)	99	–	–
Company contribution	370	–	1,623	1,184	39	38
Benefits paid *(1)*	(1,054)	(677)	(1,046)	(873)	(59)	(59)
Other	–	–	(156)	(528)	–	2
Fair value at December 31	$10,656	$10,835	$17,117	$16,765	$538	$558

(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.	
	2011	2010	2011	2010
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	$(4,141)	$(2,349)	$ (5,319)	$(2,769)
Unfunded plans	(2,238)	(1,823)	(6,632)	(6,188)
Total	$(6,379)	$(4,172)	$(11,951)	$(8,957)

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.			
	2011	2010	2011	2010	2011	2010
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	$(6,379)	$(4,172)	$(11,951)	$(8,957)	$(7,342)	$(6,773)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	$ 1	$ 1	$ 245	$ 400	$ –	$ –
Current liabilities	(237)	(257)	(346)	(336)	(341)	(343)
Postretirement benefits reserves	(6,143)	(3,916)	(11,850)	(9,021)	(7,001)	(6,430)
Total recorded	$(6,379)	$(4,172)	$(11,951)	$(8,957)	$(7,342)	$(6,773)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	$ 6,475	$ 5,028	$ 11,170	$ 7,795	$ 2,291	$ 1,985
Prior service cost	74	83	745	674	119	154
Total recorded in accumulated other comprehensive income	$ 6,549	$ 5,111	$ 11,915	$ 8,469	$ 2,410	$ 2,139

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

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 and the long-term return assumption for each asset class.

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*				
Discount rate	5.50	6.00	6.25	4.80	5.20	5.50	5.50	6.00	6.25
Long-term rate of return on funded assets	7.50	7.50	8.00	6.80	6.70	7.30	7.50	7.50	8.00
Long-term rate of compensation increase	5.25	5.25	5.00	5.20	5.00	4.70	5.25	5.25	5.00
Components of net periodic benefit cost					*(millions of dollars)*				
Service cost	$ 546	$ 468	$ 438	$ 574	$ 480	$ 421	$ 121	$ 101	$ 94
Interest cost	792	798	809	1,267	1,175	1,121	393	395	408
Expected return on plan assets	(769)	(726)	(656)	(1,168)	(1,010)	(886)	(41)	(37)	(35)
Amortization of actuarial loss/(gain)	485	525	694	647	554	648	162	147	176
Amortization of prior service cost	9	2	–	103	84	79	35	52	69
Net pension enhancement and curtailment/settlement expense	286	321	485	34	9	2	–	–	–
Net periodic benefit cost	$1,349	$1,388	$ 1,770	$ 1,457	$ 1,292	$1,385	$ 670	$ 658	$ 712
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	$2,218	$ 44	$ (231)	$ 4,133	$ 1,202	$ (33)	$ 468	$ 251	$(107)
Amortization of actuarial (loss)/gain	(771)	(846)	(1,179)	(681)	(563)	(650)	(162)	(147)	(176)
Prior service cost/(credit)	–	80	–	187	160	69	–	26	–
Amortization of prior service (cost)/credit	(9)	(2)	–	(103)	(84)	(79)	(35)	(52)	(69)
Foreign exchange rate changes	–	–	–	(90)	96	608	–	2	2
Total recorded in other comprehensive income	1,438	(724)	(1,410)	3,446	811	(85)	271	80	(350)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	$2,787	$ 664	$ 360	$ 4,903	$ 2,103	$1,300	$ 941	$ 738	$ 362

Costs for defined contribution plans were $378 million, $347 million and $339 million in 2011, 2010 and 2009, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2011	2010	2009
(Charge)/credit to other comprehensive income, before tax		*(millions of dollars)*	
U.S. pension	$(1,438)	$ 724	$1,410
Non-U.S. pension	(3,446)	(811)	85
Other postretirement benefits	(271)	(80)	350
Total (charge)/credit to other comprehensive income, before tax	(5,155)	(167)	1,845
(Charge)/credit to income tax (see Note 18)	1,495	35	(591)
(Charge)/credit to investment in equity companies	(30)	11	(133)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	$(3,690)	$(121)	$1,121
Charge/(credit) to equity of noncontrolling interests	288	95	93
(Charge)/credit to other comprehensive income attributable to ExxonMobil	$(3,402)	$ (26)	$1,214

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. The target asset allocation for the U.S. benefit plans is 50 percent equity securities and 50 percent debt securities. The target asset allocation for the non-U.S. plans in aggregate is 47 percent equities, 50 percent debt and 3 percent real estate funds. 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 2011 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, 2011, Using:				Fair Value Measurement at December 31, 2011, 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)				*(millions of dollars)*		
Asset category:								
Equity securities								
U.S.	$ –	$ 2,247*(1)*	$ –	$ 2,247	$ –	$ 2,589*(1)*	$ –	$ 2,589
Non-U.S.	–	2,636*(1)*	–	2,636	194*(2)*	4,835*(1)*	–	5,029
Private equity	–	–	458*(3)*	458	–	–	393*(3)*	393
Debt securities								
Corporate	–	2,728*(4)*	–	2,728	2*(5)*	1,857*(4)*	–	1,859
Government	–	2,482*(4)*	–	2,482	186*(5)*	6,317*(4)*	–	6,503
Asset-backed	–	11*(4)*	–	11	–	102*(4)*	–	102
Private mortgages	–	–	–	–	–	–	4*(6)*	4
Real estate funds	–	–	–	–	–	–	397*(7)*	397
Cash	–	71*(8)*	–	71	76	13*(9)*	–	89
Total at fair value	$ –	$10,175	$458	$10,633	$458	$15,713	$794	$16,965
Insurance contracts at contract value				23				152
Total plan assets				$10,656				$17,117

(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 private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

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

(8) 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.

(9) 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, 2011, 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.	$ –	$166(1)	$ –	$166
Non-U.S.	–	155(1)	–	155
Private equity	–	–	7(2)	7
Debt securities				
Corporate	–	77(3)	–	77
Government	–	120(3)	–	120
Asset-backed	–	12(3)	–	12
Private mortgages	–	–	–	–
Cash	–	1	–	1
Total at fair value	$ –	$531	$ 7	$538

(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 2011 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2011						
	Pension					Other Postretirement	
	U.S.		Non U.S.				
	Private Equity	Private Mortgages	Private Equity	Private Mortgages	Real Estate	Private Equity	Private Mortgages
	(millions of dollars)						
Fair value at January 1	$408	$ 128	$315	$4	$417	$5	$ 2
Net realized gains/(losses)	1	5	7	–	3	–	–
Net unrealized gains/(losses)	56	–	33	–	6	2	–
Net purchases/(sales)	(7)	(133)	38	–	(29)	–	(2)
Fair value at December 31	$458	$ –	$393	$4	$397	$7	$ –

The 2010 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, 2010, Using:				Fair Value Measurement at December 31, 2010, 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)				*(millions of dollars)*		
Asset category:								
Equity securities								
U.S.	$ –	$ 2,648*(1)*	$ –	$ 2,648	$ –	$ 2,443*(1)*	$ –	$ 2,443
Non-U.S.	–	3,530*(1)*	–	3,530	228*(2)*	6,502*(1)*	–	6,730
Private equity	–	–	408*(3)*	408	–	–	315*(3)*	315
Debt securities								
Corporate	–	1,152*(4)*	–	1,152	2*(5)*	1,629*(4)*	–	1,631
Government	–	2,847*(4)*	–	2,847	146*(5)*	4,709*(4)*	–	4,855
Asset-backed	–	31*(4)*	–	31	–	98*(4)*	–	98
Private mortgages	–	–	128*(6)*	128	–	–	4*(6)*	4
Real estate funds	–	–	–	–	–	–	417*(7)*	417
Cash	68	–	–	68	63	51*(8)*	–	114
Total at fair value	$ 68	$10,208	$536	$10,812	$439	$15,432	$736	$16,607
Insurance contracts at contract value				23				158
Total plan assets				$10,835				$16,765

(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 private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

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

(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, 2010, 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.	$ –	$180*(1)*	$ –	$180
Non-U.S.	–	191*(1)*	–	191
Private equity	–	–	5*(2)*	5
Debt securities				
Corporate	–	49*(3)*	–	49
Government	–	117*(3)*	–	117
Asset-backed	–	13*(3)*	–	13
Private mortgages	–	–	2*(4)*	2
Cash	1	–	–	1
Total at fair value	$ 1	$550	$ 7	$558

(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.

(4) For private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

The change in the fair value in 2010 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2010						
	Pension					Other Postretirement	
	U.S.		Non U.S.				
	Private Equity	Private Mortgages	Private Equity	Private Mortgages	Real Estate	Private Equity	Private Mortgages
	(millions of dollars)						
Fair value at January 1	$349	$ 280	$239	$ 5	$413	$4	$ 3
Net realized gains/(losses)	–	36	(1)	(1)	–	–	1
Net unrealized gains/(losses)	47	(3)	26	1	(4)	1	–
Net purchases/(sales)	12	(185)	51	(1)	8	–	(2)
Fair value at December 31	$408	$ 128	$315	$ 4	$417	$5	$ 2

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.	
	2011	**2010**	**2011**	**2010**
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$14,797	$13,184	$17,668	$9,865
Accumulated benefit obligation	12,606	11,383	16,175	9,074
Fair value of plan assets	10,655	10,834	12,832	7,131
For unfunded pension plans:				
Projected benefit obligation	$ 2,238	$ 1,823	$ 6,632	$6,188
Accumulated benefit obligation	1,475	1,381	5,753	5,413

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2012 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	$1,033	$889	$173
Prior service cost *(2)*	7	109	34

(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 2012	$1,650	$1,250	$ –	$ –
Benefit payments expected in:				
2012	1,490	1,342	442	23
2013	1,579	1,360	458	25
2014	1,547	1,383	472	26
2015	1,524	1,418	485	27
2016	1,489	1,462	497	28
2017 - 2021	6,616	7,731	2,611	163

17. Disclosures about Segments and Related Information

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

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

Earnings after income tax include special items, and transfers are at estimated market prices. Earnings for 2009 included a special charge of $140 million in the corporate and financing segment for interest related to the Valdez punitive damages award.

Interest expense includes non-debt-related interest expense of $165 million, $41 million and $500 million in 2011, 2010 and 2009, respectively. Higher expenses in 2009 primarily reflect interest provisions related to the Valdez litigation.

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

	Upstream U.S.	Upstream Non-U.S.	Downstream U.S.	Downstream Non-U.S.	Chemical U.S.	Chemical Non-U.S.	Corporate and Financing	Corporate Total
	(millions of dollars)							
As of December 31, 2011								
Earnings after income tax	$ 5,096	$ 29,343	$ 2,268	$ 2,191	$ 2,215	$ 2,168	$ (2,221)	$ 41,060
Earnings of equity companies included above	2,045	11,768	7	353	198	1,365	(447)	15,289
Sales and other operating revenue *(1)*	14,023	32,419	120,844	257,779	15,466	26,476	22	467,029
Intersegment revenue	9,807	49,910	18,489	73,549	12,226	10,563	262	–
Depreciation and depletion expense	4,879	7,021	650	1,560	380	458	635	15,583
Interest revenue	–	–	–	–	–	–	135	135
Interest expense	30	36	10	24	2	(1)	146	247
Income taxes	2,852	25,755	1,123	696	1,027	465	(867)	31,051
Additions to property, plant and equipment	10,887	18,934	400	1,334	241	910	932	33,638
Investments in equity companies	2,963	8,439	210	1,358	253	3,973	(228)	16,968
Total assets	82,900	127,977	18,354	51,132	7,245	19,862	23,582	331,052
As of December 31, 2010								
Earnings after income tax	$ 4,272	$ 19,825	$ 770	$ 2,797	$ 2,422	$ 2,491	$ (2,117)	$ 30,460
Earnings of equity companies included above	1,261	8,415	23	225	171	1,163	(581)	10,677
Sales and other operating revenue *(1)*	8,895	26,046	93,599	206,042	13,402	22,119	22	370,125
Intersegment revenue	8,102	39,066	13,546	52,697	9,694	8,421	282	–
Depreciation and depletion expense	3,506	7,574	681	1,565	421	432	581	14,760
Interest revenue	–	–	–	–	–	–	118	118
Interest expense	20	25	1	19	1	4	189	259
Income taxes	2,219	18,627	360	560	736	347	(1,288)	21,561
Additions to property, plant and equipment	52,300	16,937	888	1,332	247	1,733	719	74,156
Investments in equity companies	2,636	9,625	254	1,240	285	3,586	(197)	17,429
Total assets	76,725	115,646	18,378	47,402	7,148	19,087	18,124	302,510
As of December 31, 2009								
Earnings after income tax	$ 2,893	$ 14,214	$ (153)	$ 1,934	$ 769	$ 1,540	$ (1,917)	$ 19,280
Earnings of equity companies included above	1,216	5,269	(102)	188	164	906	(498)	7,143
Sales and other operating revenue *(1)*	3,406	21,355	76,467	173,404	9,962	16,885	21	301,500
Intersegment revenue	6,718	32,982	10,168	39,190	7,185	6,947	284	–
Depreciation and depletion expense	1,768	6,376	687	1,665	400	457	564	11,917
Interest revenue	–	–	–	–	–	–	179	179
Interest expense	38	27	10	18	4	1	450	548
Income taxes	1,451	15,183	(164)	(22)	281	(182)	(1,428)	15,119
Additions to property, plant and equipment	2,973	13,307	1,449	1,447	294	2,553	468	22,491
Investments in equity companies	2,440	8,864	323	1,190	259	2,873	(207)	15,742
Total assets	24,940	102,372	17,493	45,098	7,044	17,117	19,259	233,323

Geographic

Sales and other operating revenue *(1)*	2011	2010	2009
	(millions of dollars)		
United States	$150,343	$115,906	$ 89,847
Non-U.S.	316,686	254,219	211,653
Total	$467,029	$370,125	$301,500
Significant non-U.S. revenue sources include:			
United Kingdom	$ 34,833	$ 24,637	$ 20,293
Canada	34,626	27,243	21,151
Japan	31,925	27,143	22,054
Belgium	26,926	21,139	16,857
France	18,510	13,920	12,042
Germany	17,034	14,301	14,839
Italy	16,288	14,132	12,997
Singapore	14,400	11,088	8,400

Long-lived assets	2011	2010	2009
	(millions of dollars)		
United States	$ 91,146	$ 86,021	$ 37,138
Non-U.S.	123,518	113,527	101,978
Total	$214,664	$199,548	$139,116
Significant non-U.S. long-lived assets include:			
Canada	$ 24,458	$ 20,879	$ 15,919
Nigeria	11,806	11,429	11,046
Angola	10,395	8,570	7,320
Australia	9,474	6,570	4,247
Singapore	9,285	8,610	7,238
Kazakhstan	7,022	5,938	4,748
Norway	6,039	6,988	7,251
United Kingdom	5,008	6,177	7,609

(1) Sales and other operating revenue includes sales-based taxes of $33,503 million for 2011, $28,547 million for 2010 and $25,936 million for 2009. See Note 1, Summary of Accounting Policies.

18. Income, Sales-Based and Other Taxes

	2011			2010			2009		
	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	$ 1,547	$28,849	$ 30,396	$1,224	$21,093	$22,317	$ (838)	$15,830	$14,992
Deferred – net	1,577	(1,417)	160	49	(1,191)	(1,142)	650	(665)	(15)
U.S. tax on non-U.S. operations	15	–	15	46	–	46	32	–	32
Total federal and non-U.S.	3,139	27,432	30,571	1,319	19,902	21,221	(156)	15,165	15,009
State	480	–	480	340	–	340	110	–	110
Total income tax expense	3,619	27,432	31,051	1,659	19,902	21,561	(46)	15,165	15,119
Sales-based taxes	5,652	27,851	33,503	6,182	22,365	28,547	6,271	19,665	25,936
All other taxes and duties									
Other taxes and duties	1,539	38,434	39,973	776	35,342	36,118	581	34,238	34,819
Included in production and manufacturing expenses	1,342	1,425	2,767	1,001	1,237	2,238	699	1,318	2,017
Included in SG&A expenses	181	623	804	201	570	771	197	538	735
Total other taxes and duties	3,062	40,482	43,544	1,978	37,149	39,127	1,477	36,094	37,571
Total	$12,333	$95,765	$108,098	$9,819	$79,416	$89,235	$7,702	$70,924	$78,626

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 $330 million in 2011 and $9 million in 2009 and a net charge of $175 million in 2010 for the effect of changes in tax laws and rates.

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

	2011	2010	2009
	(millions of dollars)		
Cumulative foreign exchange translation adjustment	$ 89	$ (42)	$(247)
Postretirement benefits reserves adjustment:			
Net actuarial loss/(gain)	2,016	553	(94)
Amortization of actuarial loss/(gain)	(503)	(609)	(649)
Prior service cost	47	92	20
Amortization of prior service cost	(41)	(45)	(43)
Foreign exchange rate changes	(24)	44	175
Total postretirement benefits reserves adjustment	1,495	35	(591)
Other components of equity	236	246	140

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2011, 2010 and 2009 is as follows:

	2011	2010	2009
	(millions of dollars)		
Income before income taxes			
United States	$11,511	$ 7,711	$ 2,576
Non-U.S.	61,746	45,248	32,201
Total	$73,257	$52,959	$34,777
Theoretical tax	$25,640	$18,536	$12,172
Effect of equity method of accounting	(5,351)	(3,737)	(2,500)
Non-U.S. taxes in excess of theoretical U.S. tax	10,385	7,293	5,948
U.S. tax on non-U.S. operations	15	46	32
State taxes, net of federal tax benefit	312	221	72
Other U.S.	50	(798)	(605)
Total income tax expense	$31,051	$21,561	$15,119
Effective tax rate calculation			
Income taxes	$31,051	$21,561	$15,119
ExxonMobil share of equity company income taxes	5,603	4,058	2,489
Total income taxes	36,654	25,619	17,608
Net income including noncontrolling interests	42,206	31,398	19,658
Total income before taxes	$78,860	$57,017	$37,266
Effective income tax rate	46%	45%	47%

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:	2011	2010
	(millions of dollars)	
Property, plant and equipment	$ 45,951	$ 42,657
Other liabilities	4,281	4,278
Total deferred tax liabilities	$ 50,232	$ 46,935
Pension and other postretirement benefits	$ (7,930)	$ (5,634)
Asset retirement obligations	(5,302)	(4,461)
Tax loss carryforwards	(3,166)	(3,243)
Other assets	(7,079)	(6,070)
Total deferred tax assets	$(23,477)	$(19,408)
Asset valuation allowances	1,304	1,183
Net deferred tax liabilities	$ 28,059	$ 28,710

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	2011	2010
	(millions of dollars)	
Other current assets	$ (4,549)	$ (3,359)
Other assets, including intangibles, net	(4,218)	(3,527)
Accounts payable and accrued liabilities	208	446
Deferred income tax liabilities	36,618	35,150
Net deferred tax liabilities	$28,059	$28,710

The Corporation had $47 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. Unrecognized deferred taxes on remittance of these funds are not expected to be material.

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. Resolution of the related 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 50 percent in the next 12 months, with no material impact on near-term earnings. Given the long time periods involved in resolving tax positions, the Corporation does not expect that the recognition of unrecognized tax benefits will have a material impact on the Corporation's effective income tax rate in any given year.

The following table summarizes the movement in unrecognized tax benefits.

Gross unrecognized tax benefits	2011	2010	2009
		(millions of dollars)	
Balance at January 1	$4,148	$4,725	$4,976
Additions based on current year's tax positions	822	830	547
Additions for prior years' tax positions	451	620	262
Reductions for prior years' tax positions	(329)	(505)	(594)
Reductions due to lapse of the statute of limitations	–	(534)	–
Settlements with tax authorities	(145)	(999)	(592)
Foreign exchange effects/other	(25)	11	126
Balance at December 31	$4,922	$4,148	$4,725

The additions and reductions in unrecognized tax benefits shown above include effects related to net income and equity, and timing differences for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. The 2011, 2010 and 2009 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income or cash flow.

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

Country of Operation	Open Tax Years
Abu Dhabi	2000 - 2011
Angola	2007 - 2011
Australia	2000 - 2011
Canada	1994 - 2011
Equatorial Guinea	2006 - 2011
Germany	1999 - 2011
Japan	2004 - 2011
Malaysia	2005 - 2011
Nigeria	1998 - 2011
Norway	2000 - 2011
United Kingdom	2009 - 2011
United States	2004 - 2011

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 $62 million in interest expense on income tax reserves in 2011. For 2010, interest expense was a credit of $39 million, reflecting the effect of credits from the net favorable resolution of prior year tax positions. The Corporation incurred approximately $135 million in interest expense on income tax reserves in 2009. The related interest payable balances were $662 million and $636 million at December 31, 2011, and 2010, respectively.

19. Acquisition of XTO Energy Inc.

Description of the Transaction. On June 25, 2010, ExxonMobil acquired XTO Energy Inc. (XTO) by merging a wholly-owned subsidiary of ExxonMobil with and into XTO (the "merger"), with XTO continuing as the surviving corporation and wholly-owned subsidiary of ExxonMobil. XTO is involved in the exploration for, production of, and transportation and sale of crude oil and natural gas.

At the effective time of the merger, each share of XTO common stock was converted into the right to receive 0.7098 shares of common stock of ExxonMobil (the "Exchange Ratio"), with cash being paid in lieu of any fractional shares of ExxonMobil stock. Also at the effective time, each outstanding option to purchase XTO common stock was converted into an option to purchase a number of shares of ExxonMobil stock based on the Exchange Ratio, and each outstanding stock-based award of XTO was converted into a stock-based award of ExxonMobil stock based on the Exchange Ratio.

The components of the consideration transferred follow:

	(millions of dollars)
Consideration attributable to stock issued (1) (2)	$24,480
Consideration attributable to converted stock options (2)	179
Total consideration transferred	$24,659

(1) *The fair value of the Corporation's common stock on the acquisition date was $59.10 per share based on the closing value on the NYSE. The Corporation issued 416 million shares of stock previously held in treasury. The treasury stock issued, based on the average cost, was valued at $21,139 million. The excess of the fair value of the consideration transferred over the cost of treasury stock issued was $3,520 million and was included in common stock without par value.*

(2) *The portion of the fair value of XTO converted stock-based awards attributable to pre-merger employee service was part of consideration. The remaining fair value of the awards is recognized over the requisite service period.*

Recording of Assets Acquired and Liabilities Assumed. The transaction was accounted for using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date.

The following table summarizes the assets acquired and liabilities assumed:

	(millions of dollars)
Current assets	$ 2,053
Property, plant and equipment (1)	47,300
Goodwill (2)	39
Other assets	620
Total assets acquired	$50,012
Current liabilities	$ 2,615
Long-term debt (3)	10,574
Deferred income tax liabilities (4)	11,204
Other long-term obligations	960
Total liabilities assumed	$25,353
Net assets acquired	$24,659

(1) *Property, plant and equipment were measured primarily using an income approach. The fair value measurements of the oil and gas assets were based, in part, on significant inputs not observable in the market and thus represent a Level 3 measurement. The significant inputs included XTO resources, assumed future production profiles, commodity prices (mainly based on observable market inputs), risk adjusted discount rate of 7 percent, inflation of 2 percent and assumptions on the timing and amount of future development and operating costs. The property, plant and equipment additions were segmented to the Upstream business, with substantially all of the assets in the United States.*

(2) *Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill was recognized in the Upstream reporting unit. Goodwill is not amortized and is not deductible for tax purposes.*

(3) *Long-term debt was recognized at market rates at closing (Level 1).*

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

The 2010 unaudited pro forma revenues of $373 billion, net income attributable to ExxonMobil of $31 billion, earnings per common share of $6.03 and earnings per common share assuming dilution of $6.01 for the Corporation were calculated as if the merger of XTO had occurred at the beginning of 2010. The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the merger and factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the consolidated results of operations actually would have been had the merger been completed on January 1, 2010. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations of the combined company. The unaudited pro forma consolidated results reflect pro forma adjustments for the elimination of deferred gains and losses recognized in earnings for derivatives outstanding at the beginning of the year, depreciation expense related to the fair value adjustment to property, plant and equipment acquired, additional amortization expense related to the fair value of identifiable intangible assets acquired, capitalization of interest expense and applicable income tax impacts.

20. Subsequent Event

On January 29, 2012, the Corporation announced that it had entered into an agreement which will result in the restructuring of its Downstream and Chemical holdings in Japan. Under the agreement, TonenGeneral Sekiyu K. K. (TG), a consolidated subsidiary owned 50 percent by the Corporation, will purchase for approximately $3.9 billion the Corporation's shares of a wholly-owned affiliate in Japan, ExxonMobil Yugen Kaisha, which will result in TG acquiring approximately 200 million of its shares currently owned by the Corporation along with other assets. As a result of the restructuring the Corporation's effective ownership of TG will be reduced to approximately 22 percent. Closing is anticipated in mid-2012.

The major classes of assets and liabilities that would have been classified as held for sale if the transaction had met the criteria for held for sale accounting at December 31, 2011, were as follows:

	(millions of dollars)
Assets	
Current assets *(1)*	$ 6,862
Net property, plant and equipment	4,740
Other assets	1,757
Total assets	$13,359
Liabilities	
Current liabilities	$ 8,450
Postretirement benefits reserves	2,103
Other long-term obligations	1,179
Total liabilities	$11,732
Equity	
ExxonMobil share of equity *(2)*	$ (467)
Noncontrolling interests	2,094
Total equity	$ 1,627
Total liabilities and equity	$13,359

(1) Current assets include $1,882 million of crude oil, products and merchandise inventory.

(2) On the date the Corporation transfers control to TG, the ExxonMobil share of accumulated other comprehensive income will be recycled as a benefit to earnings. At December 31, 2011, the total accumulated other comprehensive income was $1,482 million.

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 $2,600 million in 2011, $249 million in 2010, and $536 million in 2009. 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							
2011 – Revenue							
Sales to third parties	$ 8,579	$1,056	$ 8,050	$ 3,507	$ 6,813	$1,061	$29,066
Transfers	8,190	7,022	7,694	16,704	9,388	1,213	50,211
	$16,769	$8,078	$15,744	$20,211	$16,201	$2,274	$79,277
Production costs excluding taxes	4,107	2,751	2,722	2,608	1,672	497	14,357
Exploration expenses	268	290	599	233	618	73	2,081
Depreciation and depletion	4,664	980	1,928	2,159	1,680	236	11,647
Taxes other than income	2,157	79	631	2,055	2,164	295	7,381
Related income tax	2,445	969	6,842	7,888	6,026	353	24,523
Results of producing activities for consolidated subsidiaries	$ 3,128	$3,009	$ 3,022	$ 5,268	$ 4,041	$ 820	$19,288
Equity Companies							
2011 – Revenue							
Sales to third parties	$ 1,356	$ –	$ 5,580	$ –	$18,855	$ –	$25,791
Transfers	1,163	–	103	–	5,666	–	6,932
	$ 2,519	$ –	$ 5,683	$ –	$24,521	$ –	$32,723
Production costs excluding taxes	482	–	315	–	378	–	1,175
Exploration expenses	10	–	13	–	–	–	23
Depreciation and depletion	151	–	160	–	576	–	887
Taxes other than income	36	–	2,995	–	6,173	–	9,204
Related income tax	–	–	847	–	8,036	–	8,883
Results of producing activities for equity companies	$ 1,840	$ –	$ 1,353	$ –	$ 9,358	$ –	$12,551
Total results of operations	$ 4,968	$3,009	$ 4,375	$ 5,268	$13,399	$ 820	$31,839

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

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2010 – Revenue							
Sales to third parties	$ 5,334	$1,218	$ 6,055	$ 4,227	$ 4,578	$ 696	$22,108
Transfers	7,070	5,832	7,120	13,295	6,031	1,123	40,471
	$12,404	$7,050	$13,175	$17,522	$10,609	$1,819	$62,579
Production costs excluding taxes	2,794	2,612	2,717	2,215	1,308	462	12,108
Exploration expenses	283	464	394	587	360	56	2,144
Depreciation and depletion	3,350	1,015	2,531	2,580	1,141	219	10,836
Taxes other than income	1,188	86	482	1,742	1,298	204	5,000
Related income tax	2,093	715	4,728	6,068	3,852	262	17,718
Results of producing activities for consolidated subsidiaries	$ 2,696	$2,158	$ 2,323	$ 4,330	$ 2,650	$ 616	$14,773
Equity Companies							
2010 – Revenue							
Sales to third parties	$ 1,012	$ –	$ 5,050	$ –	$12,682	$ –	$18,744
Transfers	867	–	68	–	3,817	–	4,752
	$ 1,879	$ –	$ 5,118	$ –	$16,499	$ –	$23,496
Production costs excluding taxes	481	–	294	–	320	–	1,095
Exploration expenses	4	–	19	–	2	–	25
Depreciation and depletion	157	–	188	–	455	–	800
Taxes other than income	32	–	2,515	–	3,844	–	6,391
Related income tax	–	–	815	–	5,295	–	6,110
Results of producing activities for equity companies	$ 1,205	$ –	$ 1,287	$ –	$ 6,583	$ –	$ 9,075
Total results of operations	$ 3,901	$2,158	$ 3,610	$ 4,330	$ 9,233	$ 616	$23,848
Consolidated Subsidiaries							
2009 – Revenue							
Sales to third parties	$ 1,859	$1,345	$ 5,900	$ 3,012	$ 2,637	$ 586	$15,339
Transfers	5,652	4,538	5,977	11,868	5,433	1,066	34,534
	$ 7,511	$5,883	$11,877	$14,880	$ 8,070	$1,652	$49,873
Production costs excluding taxes	2,255	2,428	2,675	2,027	1,247	386	11,018
Exploration expenses	219	339	375	662	393	33	2,021
Depreciation and depletion	1,670	948	2,078	2,293	816	195	8,000
Taxes other than income	730	78	593	1,343	991	252	3,987
Related income tax	1,127	597	4,277	4,667	2,822	237	13,727
Results of producing activities for consolidated subsidiaries	$ 1,510	$1,493	$ 1,879	$ 3,888	$ 1,801	$ 549	$11,120
Equity Companies							
2009 – Revenue							
Sales to third parties	$ 818	$ –	$ 4,889	$ –	$ 6,148	$ –	$11,855
Transfers	686	–	53	–	2,960	–	3,699
	$ 1,504	$ –	$ 4,942	$ –	$ 9,108	$ –	$15,554
Production costs excluding taxes	481	–	248	–	251	–	980
Exploration expenses	1	–	12	–	–	–	13
Depreciation and depletion	163	–	168	–	366	–	697
Taxes other than income	37	–	2,233	–	2,120	–	4,390
Related income tax	–	–	902	–	3,121	–	4,023
Results of producing activities for equity companies	$ 822	$ –	$ 1,379	$ –	$ 3,250	$ –	$ 5,451
Total results of operations	$ 2,332	$1,493	$ 3,258	$ 3,888	$ 5,051	$ 549	$16,571

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $6,651 million less at year-end 2011 and $4,729 million less at year-end 2010 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 8. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations have been included in the capitalized costs for 2011 and 2010 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, 2011							
Property (acreage) costs – Proved	$ 10,969	$ 3,837	$ 96	$ 919	$ 1,567	$ 954	$ 18,342
– Unproved	25,398	1,402	67	430	755	128	28,180
Total property costs	$ 36,367	$ 5,239	$ 163	$ 1,349	$ 2,322	$ 1,082	$ 46,522
Producing assets	65,941	20,393	40,646	32,059	22,675	6,035	187,749
Incomplete construction	4,652	12,385	964	9,831	9,922	4,131	41,885
Total capitalized costs	$106,960	$38,017	$41,773	$43,239	$34,919	$11,248	$276,156
Accumulated depreciation and depletion	33,037	16,296	31,706	18,449	14,960	4,384	118,832
Net capitalized costs for consolidated subsidiaries	$ 73,923	$21,721	$10,067	$24,790	$19,959	$ 6,864	$157,324
Equity Companies							
As of December 31, 2011							
Property (acreage) costs – Proved	$ 76	$ –	$ 4	$ –	$ –	$ –	$ 80
– Unproved	25	–	–	–	–	–	25
Total property costs	$ 101	$ –	$ 4	$ –	$ –	$ –	$ 105
Producing assets	3,510	–	5,383	–	8,155	–	17,048
Incomplete construction	183	–	212	–	548	–	943
Total capitalized costs	$ 3,794	$ –	$ 5,599	$ –	$ 8,703	$ –	$ 18,096
Accumulated depreciation and depletion	1,354	–	4,267	–	3,068	–	8,689
Net capitalized costs for equity companies	$ 2,440	$ –	$ 1,332	$ –	$ 5,635	$ –	$ 9,407
Consolidated Subsidiaries							
As of December 31, 2010							
Property (acreage) costs – Proved	$ 8,031	$ 4,166	$ 199	$ 929	$ 1,451	$ 905	$ 15,681
– Unproved	24,697	1,260	75	418	229	211	26,890
Total property costs	$ 32,728	$ 5,426	$ 274	$ 1,347	$ 1,680	$ 1,116	$ 42,571
Producing assets	60,231	22,115	43,592	28,354	22,264	5,842	182,398
Incomplete construction	4,029	8,109	1,126	9,180	7,658	2,543	32,645
Total capitalized costs	$ 96,988	$35,650	$44,992	$38,881	$31,602	$ 9,501	$257,614
Accumulated depreciation and depletion	29,199	17,561	33,484	16,318	13,412	4,217	114,191
Net capitalized costs for consolidated subsidiaries	$ 67,789	$18,089	$11,508	$22,563	$18,190	$ 5,284	$143,423
Equity Companies							
As of December 31, 2010							
Property (acreage) costs – Proved	$ 76	$ –	$ 8	$ –	$ –	$ –	$ 84
– Unproved	2	–	–	–	–	–	2
Total property costs	$ 78	$ –	$ 8	$ –	$ –	$ –	$ 86
Producing assets	3,446	–	5,197	–	7,845	–	16,488
Incomplete construction	116	–	384	–	214	–	714
Total capitalized costs	$ 3,640	$ –	$ 5,589	$ –	$ 8,059	$ –	$ 17,288
Accumulated depreciation and depletion	1,418	–	4,252	–	2,484	–	8,154
Net capitalized costs for equity companies	$ 2,222	$ –	$ 1,337	$ –	$ 5,575	$ –	$ 9,134

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 2011 were $30,754 million, down $40,058 million from 2010, due primarily to the absence of the acquisition of XTO Energy Inc. 2010 costs were $70,812 million, up $50,305 million from 2009, due primarily to the acquisition of XTO Energy Inc. Total equity company costs incurred in 2011 were $1,226 million, up $312 million from 2010, due primarily to higher development 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 2011							
Consolidated Subsidiaries							
Property acquisition costs – Proved	$ 259	$ –	$ –	$ –	$ 96	$ –	$ 355
– Unproved	2,685	178	–	–	546	–	3,409
Exploration costs	465	372	640	303	518	154	2,452
Development costs	8,166	5,478	1,899	4,316	2,969	1,710	24,538
Total costs incurred for consolidated subsidiaries	$11,575	$6,028	$2,539	$4,619	$4,129	$1,864	$30,754
Equity Companies							
Property acquisition costs – Proved	$ –	$ –	$ –	$ –	$ –	$ –	$ –
– Unproved	23	–	–	–	–	–	23
Exploration costs	19	–	32	–	–	–	51
Development costs	339	–	164	–	649	–	1,152
Total costs incurred for equity companies	$ 381	$ –	$ 196	$ –	$ 649	$ –	$ 1,226
During 2010							
Consolidated Subsidiaries							
Property acquisition costs – Proved	$21,633	$ –	$ 41	$ 3	$ 115	$ –	$21,792
– Unproved	23,509	136	23	–	–	–	23,668
Exploration costs	690	527	550	453	545	228	2,993
Development costs	7,947	4,757	1,227	4,390	2,892	1,146	22,359
Total costs incurred for consolidated subsidiaries	$53,779	$5,420	$1,841	$4,846	$3,552	$1,374	$70,812
Equity Companies							
Property acquisition costs – Proved	$ –	$ –	$ –	$ –	$ –	$ –	$ –
– Unproved	1	–	–	–	–	–	1
Exploration costs	4	–	56	–	2	–	62
Development costs	323	–	225	–	303	–	851
Total costs incurred for equity companies	$ 328	$ –	$ 281	$ –	$ 305	$ –	$ 914
During 2009							
Consolidated Subsidiaries							
Property acquisition costs – Proved	$ 17	$ –	$ –	$ 600	$ 59	$ –	$ 676
– Unproved	188	353	1	5	62	–	609
Exploration costs	548	498	471	880	529	130	3,056
Development costs	2,482	2,394	3,384	4,596	2,542	768	16,166
Total costs incurred for consolidated subsidiaries	$ 3,235	$3,245	$3,856	$6,081	$3,192	$ 898	$20,507
Equity Companies							
Property acquisition costs – Proved	$ –	$ –	$ –	$ –	$ –	$ –	$ –
– Unproved	–	–	–	–	–	–	–
Exploration costs	1	–	54	–	–	–	55
Development costs	305	–	255	–	404	–	964
Total costs incurred for equity companies	$ 306	$ –	$ 309	$ –	$ 404	$ –	$ 1,019

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2009, 2010, and 2011.

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 2011 that were associated with production sharing contract arrangements was 14 percent of liquids, 9 percent of natural gas and 11 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.

In accordance with the Securities and Exchange Commission's rules, bitumen extracted through mining activities and hydrocarbons from other non-traditional resources are reported as oil and gas reserves beginning in 2009.

The rules in 2009 adopted a reliable technology definition that permits reserves to be added based on technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated.

The changes between 2010 year-end proved reserves and 2011 year-end proved reserves reflect the initial booking of the Kearl Expansion project in Canada.

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

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ S. Amer.	Canada/ S. Amer.	Total
							(millions of barrels)			
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2009	1,644	812	533	2,137	2,219	231	7,576	–	–	7,576
Revisions	82	(610)[(1)]	93	(33)	(130)	9	(589)	2,099[(1)]	715	2,225
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases	–	–	–	–	–	–	–	–	–	–
Sales	(1)	–	(2)	–	–	–	(3)	–	–	(3)
Extensions/discoveries	3	–	–	53	15	71	142	–	–	142
Production	(112)	(30)	(137)	(250)	(105)	(23)	(657)	(44)	(24)	(725)
December 31, 2009	1,616	172	487	1,907	1,999	288	6,469	2,055	691	9,215
Proportional interest in proved reserves of equity companies										
January 1, 2009	327	–	27	–	2,205	–	2,559	–	–	2,559
Revisions	56	–	5	–	(54)	–	7	–	–	7
Improved recovery	–	–	–	–	15	–	15	–	–	15
Purchases	–	–	–	–	–	–	–	–	–	–
Sales	–	–	–	–	–	–	–	–	–	–
Extensions/discoveries	–	–	–	–	–	–	–	–	–	–
Production	(27)	–	(2)	–	(116)	–	(145)	–	–	(145)
December 31, 2009	356	–	30	–	2,050	–	2,436	–	–	2,436
Total liquids proved reserves at December 31, 2009	1,972	172	517	1,907	4,049	288	8,905	2,055	691	11,651
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2010	1,616	172	487	1,907	1,999	288	6,469	2,055	691	9,215
Revisions	57	10	53	89	49	7	265	89	14	368
Improved recovery	4	–	–	–	–	1	5	–	–	5
Purchases	374	–	–	–	4	–	378	–	–	378
Sales	(19)	–	–	(2)	–	–	(21)	–	–	(21)
Extensions/discoveries	43	11	4	34	90	–	182	–	–	182
Production	(123)	(30)	(121)	(229)	(119)	(21)	(643)	(42)	(24)	(709)
December 31, 2010	1,952	163	423	1,799	2,023	275	6,635	2,102	681	9,418
Proportional interest in proved reserves of equity companies										
January 1, 2010	356	–	30	–	2,050	–	2,436	–	–	2,436
Revisions	17	–	3	–	(30)	–	(10)	–	–	(10)
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases	–	–	–	–	–	–	–	–	–	–
Sales	–	–	–	–	–	–	–	–	–	–
Extensions/discoveries	3	–	–	–	–	–	3	–	–	3
Production	(25)	–	(2)	–	(147)	–	(174)	–	–	(174)
December 31, 2010	351	–	31	–	1,873	–	2,255	–	–	2,255
Total liquids proved reserves at December 31, 2010	2,303	163	454	1,799	3,896	275	8,890	2,102	681	11,673

(1) Total proved reserves of 630 million barrels at January 1, 2009, associated with the Cold Lake field in Canada are reported as bitumen reserves under the amended Securities and Exchange Commission's Rule 4-10 of Regulation S-X.

Crude Oil, Natural Gas Liquids, Synthetic Oil and Bitumen 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, 2011	1,679	138	350	1,589	1,839	178	5,773	862	2,102	681	9,418
Revisions	29	10	68	52	(55)	5	109	106	53	(4)	264
Improved recovery	–	–	–	–	–	–	–	–	–	–	–
Purchases	2	–	–	–	–	–	2	14	–	–	16
Sales	(3)	(11)	(24)	–	–	–	(38)	(14)	–	–	(52)
Extensions/discoveries	55	–	3	1	57	–	116	18	995	–	1,129
Production	(102)	(19)	(80)	(179)	(120)	(13)	(513)	(81)	(44)	(24)	(662)
December 31, 2011	1,660	118	317	1,463	1,721	170	5,449	905	3,106	653	10,113
Proportional interest in proved reserves of equity companies											
January 1, 2011	350	–	31	–	1,394	–	1,775	480	–	–	2,255
Revisions	24	–	–	–	(21)	–	3	3	–	–	6
Improved recovery	–	–	–	–	–	–	–	–	–	–	–
Purchases	–	–	–	–	–	–	–	–	–	–	–
Sales	(2)	–	–	–	–	–	(2)	–	–	–	(2)
Extensions/discoveries	–	–	–	–	12	–	12	25	–	–	37
Production	(24)	–	(2)	–	(130)	–	(156)	(25)	–	–	(181)
December 31, 2011	348	–	29	–	1,255	–	1,632	483	–	–	2,115
Total liquids proved reserves at December 31, 2011	2,008	118	346	1,463	2,976	170	7,081	1,388	3,106	653	12,228

(1) Includes total proved reserves attributable to Imperial Oil Limited of 10 million barrels, as well as proved developed reserves of 10 million barrels, in which there is a 30.4 percent noncontrolling interest.

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ S. Amer. *(2)*	Canada/ S. Amer. *(3)*	Total
	(millions of barrels)									
Proved developed reserves, as of December 31, 2009										
Consolidated subsidiaries	1,211	152	376	1,122	1,268	153	4,282	468	691	5,441
Equity companies	279	–	10	–	1,608	–	1,897	–	–	1,897
Proved undeveloped reserves, as of December 31, 2009										
Consolidated subsidiaries	405	20	111	785	731	135	2,187	1,587	–	3,774
Equity companies	77	–	20	–	442	–	539	–	–	539
Total liquids proved reserves at December 31, 2009	1,972	172	517	1,907	4,049	288	8,905	2,055	691	11,651
Proved developed reserves, as of December 31, 2010										
Consolidated subsidiaries	1,478	133	361	1,055	1,306	139	4,472	519	681	5,672
Equity companies	271	–	21	–	1,623	–	1,915	–	–	1,915
Proved undeveloped reserves, as of December 31, 2010										
Consolidated subsidiaries	474	30	62	744	717	136	2,163	1,583	–	3,746
Equity companies	80	–	10	–	250	–	340	–	–	340
Total liquids proved reserves at December 31, 2010	2,303	163	454	1,799	3,896	275	8,890	2,102	681	11,673
Proved developed reserves, as of December 31, 2011										
Consolidated subsidiaries	1,452	109	302	1,050	1,160	126	4,199	519	653	5,371
Equity companies	270	–	28	–	1,457	–	1,755	–	–	1,755
Proved undeveloped reserves, as of December 31, 2011										
Consolidated subsidiaries	567	26	74	625	727	136	2,155	2,587	–	4,742
Equity companies	83	–	1	–	276	–	360	–	–	360
Total liquids proved reserves at December 31, 2011	2,372	135	405	1,675	3,620	262	8,469*(4)*	3,106	653	12,228

(1) Includes total proved reserves attributable to Imperial Oil Limited of 63 million barrels in 2009, 57 million barrels in 2010 and 55 million barrels in 2011, as well as proved developed reserves of 62 million barrels in 2009, 56 million barrels in 2010 and 55 million barrels in 2011, and in addition, proved undeveloped reserves of 1 million barrels in 2009 and 1 million barrels in 2010, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 1,661 million barrels in 2009, 1,715 million barrels in 2010 and 2,413 million barrels in 2011, as well as proved developed reserves of 468 million barrels in 2009, 519 million barrels in 2010 and 519 million barrels in 2011, and in addition, proved undeveloped reserves of 1,193 million barrels in 2009, 1,196 million barrels in 2010 and 1,894 million barrels in 2011, in which there is a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 691 million barrels in 2009, 681 million barrels in 2010 and 653 million barrels in 2011, as well as proved developed reserves of 691 million barrels in 2009, 681 million barrels in 2010 and 653 million barrels in 2011, in which there is a 30.4 percent noncontrolling interest.

(4) See previous page 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 2011 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							
	United States	Canada/ S. Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products** *(2)*
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2009	11,778	1,383	5,445	918	9,857	2,021	31,402	12,810
Revisions	320	248	79	45	(980)	40	(248)	2,183
Improved recovery	–	–	–	–	–	–	–	–
Purchases	8	–	–	–	–	–	8	1
Sales	(10)	(2)	(1)	–	–	–	(13)	(5)
Extensions/discoveries	158	–	–	–	11	5,507	5,676	1,088
Production	(566)	(261)	(800)	(43)	(585)	(128)	(2,383)	(1,122)
December 31, 2009	11,688	1,368	4,723	920	8,303	7,440	34,442	14,955
Proportional interest in proved reserves of equity companies								
January 1, 2009	112	–	11,839	–	22,526	–	34,477	8,305
Revisions	8	–	186	–	189	–	383	71
Improved recovery	–	–	–	–	–	–	–	15
Purchases	–	–	–	–	–	–	–	–
Sales	–	–	–	–	–	–	–	–
Extensions/discoveries	–	–	18	–	–	–	18	3
Production	(6)	–	(593)	–	(714)	–	(1,313)	(364)
December 31, 2009	114	–	11,450	–	22,001	–	33,565	8,030
Total proved reserves at December 31, 2009	11,802	1,368	16,173	920	30,304	7,440	68,007	22,985
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2010	11,688	1,368	4,723	920	8,303	7,440	34,442	14,955
Revisions	832	123	(26)	6	(333)	42	644	475
Improved recovery	–	–	–	–	–	–	–	5
Purchases	12,774	–	15	–	–	–	12,789	2,510
Sales	(104)	(2)	–	–	–	–	(106)	(38)
Extensions/discoveries	1,861	3	49	25	25	1	1,964	509
Production	(1,057)	(234)	(719)	(43)	(735)	(132)	(2,920)	(1,196)
December 31, 2010	25,994	1,258	4,042	908	7,260	7,351	46,813	17,220
Proportional interest in proved reserves of equity companies								
January 1, 2010	114	–	11,450	–	22,001	–	33,565	8,030
Revisions	8	–	(4)	–	231	–	235	30
Improved recovery	–	–	–	–	–	–	–	–
Purchases	–	–	–	–	–	–	–	–
Sales	–	–	–	–	–	–	–	–
Extensions/discoveries	–	–	24	–	–	–	24	7
Production	(5)	–	(724)	–	(1,093)	–	(1,822)	(478)
December 31, 2010	117	–	10,746	–	21,139	–	32,002	7,589
Total proved reserves at December 31, 2010	26,111	1,258	14,788	908	28,399	7,351	78,815	24,809

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent Total All Products (2)
	United States	Canada/ S. 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, 2011	25,994	1,258	4,042	908	7,260	7,351	46,813	17,220
Revisions	(236)	55	310	113	(231)	28	39	271
Improved recovery	–	–	–	–	–	–	–	–
Purchases	303	–	–	–	–	–	303	67
Sales	(32)	(347)	(140)	–	–	–	(519)	(138)
Extensions/discoveries	1,779	42	29	–	192	–	2,042	1,469
Production	(1,554)	(173)	(655)	(39)	(750)	(132)	(3,303)	(1,213)
December 31, 2011	26,254	835	3,586	982	6,471	7,247	45,375	17,676
Proportional interest in proved reserves of equity companies								
January 1, 2011	117	–	10,746	–	21,139	–	32,002	7,589
Revisions	1	–	53	–	(29)	–	25	10
Improved recovery	–	–	–	–	–	–	–	–
Purchases	–	–	–	–	–	–	–	–
Sales	(1)	–	(3)	–	–	–	(4)	(3)
Extensions/discoveries	–	–	13	–	627	–	640	144
Production	(5)	–	(640)	–	(1,171)	–	(1,816)	(484)
December 31, 2011	112	–	10,169	–	20,566	–	30,847	7,256
Total proved reserves at December 31, 2011	26,366	835	13,755	982	27,037	7,247	76,222	24,932

(1) Includes total proved reserves attributable to Imperial Oil Limited of 590 billion cubic feet in 2009, 576 billion cubic feet in 2010 and 422 billion cubic feet in 2011, as well as proved developed reserves of 526 billion cubic feet in 2009, 507 billion cubic feet in 2010 and 360 billion cubic feet in 2011, and in addition, proved undeveloped reserves of 64 billion cubic feet in 2009, 69 billion cubic feet in 2010 and 62 billion cubic feet in 2011, 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							
	United States	Canada/ S. Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2009								
Consolidated subsidiaries	7,492	1,200	3,920	739	7,407	1,262	22,020	9,111
Equity companies	90	–	8,862	–	17,799	–	26,751	6,356
Proved undeveloped reserves, as of December 31, 2009								
Consolidated subsidiaries	4,196	168	803	181	896	6,178	12,422	5,844
Equity companies	24	–	2,588	–	4,202	–	6,814	1,674
Total proved reserves at December 31, 2009	11,802	1,368	16,173	920	30,304	7,440	68,007	22,985
Proved developed reserves, as of December 31, 2010								
Consolidated subsidiaries	15,344	1,077	3,516	711	6,593	1,174	28,415	10,408
Equity companies	97	–	8,167	–	20,494	–	28,758	6,708
Proved undeveloped reserves, as of December 31, 2010								
Consolidated subsidiaries	10,650	181	526	197	667	6,177	18,398	6,812
Equity companies	20	–	2,579	–	645	–	3,244	881
Total proved reserves at December 31, 2010	26,111	1,258	14,788	908	28,399	7,351	78,815	24,809
Proved developed reserves, as of December 31, 2011								
Consolidated subsidiaries	15,450	658	3,041	853	5,762	1,070	26,834	9,843
Equity companies	83	–	7,588	–	19,305	–	26,976	6,251
Proved undeveloped reserves, as of December 31, 2011								
Consolidated subsidiaries	10,804	177	545	129	709	6,177	18,541	7,833
Equity companies	29	–	2,581	–	1,261	–	3,871	1,005
Total proved reserves at December 31, 2011	26,366	835	13,755	982	27,037	7,247	76,222	24,932

(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, 2009							
Future cash inflows							
from sales of oil and gas	$112,408	$147,597	$54,074	$110,475	$121,110	$39,127	$584,791
Future production costs	47,660	62,241	16,412	28,679	29,769	12,571	197,332
Future development costs	15,544	25,738	12,565	15,155	10,256	11,655	90,913
Future income tax expenses	22,058	14,572	16,065	32,784	46,286	4,739	136,504
Future net cash flows	$ 27,146	$ 45,046	$ 9,032	$ 33,857	$ 34,799	$10,162	$160,042
Effect of discounting net cash flows at 10%	15,563	31,980	2,569	14,192	20,698	9,194	94,196
Discounted future net cash flows	$ 11,583	$ 13,066	$ 6,463	$ 19,665	$ 14,101	$ 968	$ 65,846
Equity Companies							
As of December 31, 2009							
Future cash inflows							
from sales of oil and gas	$ 19,705	$ –	$94,401	$ –	$180,253	$ –	$294,359
Future production costs	5,847	–	60,869	–	54,493	–	121,209
Future development costs	2,862	–	3,220	–	2,759	–	8,841
Future income tax expenses	–	–	12,003	–	44,733	–	56,736
Future net cash flows	$ 10,996	$ –	$18,309	$ –	$ 78,268	$ –	$107,573
Effect of discounting net cash flows at 10%	6,332	–	9,845	–	42,086	–	58,263
Discounted future net cash flows	$ 4,664	$ –	$ 8,464	$ –	$ 36,182	$ –	$ 49,310
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 16,247	$ 13,066	$14,927	$ 19,665	$ 50,283	$ 968	$115,156

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $10,088 million in 2009, 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, 2010							
Future cash inflows from sales of oil and gas	$221,298	$184,671	$60,086	$137,476	$156,337	$55,087	$ 814,955
Future production costs	76,992	69,765	15,246	31,189	36,318	16,347	245,857
Future development costs	28,905	22,130	12,155	15,170	13,716	11,652	103,728
Future income tax expenses	44,128	21,798	21,736	46,145	59,477	9,591	202,875
Future net cash flows	$ 71,273	$ 70,978	$10,949	$ 44,972	$ 46,826	$17,497	$ 262,495
Effect of discounting net cash flows at 10%	39,545	45,607	2,765	18,046	28,883	13,411	148,257
Discounted future net cash flows	$ 31,728	$ 25,371	$ 8,184	$ 26,926	$ 17,943	$ 4,086	$ 114,238
Equity Companies							
As of December 31, 2010							
Future cash inflows from sales of oil and gas	$ 26,110	$ –	$73,222	$ –	$232,334	$ –	$ 331,666
Future production costs	6,369	–	49,010	–	73,508	–	128,887
Future development costs	2,883	–	2,719	–	2,523	–	8,125
Future income tax expenses	–	–	8,348	–	57,041	–	65,389
Future net cash flows	$ 16,858	$ –	$13,145	$ –	$ 99,262	$ –	$ 129,265
Effect of discounting net cash flows at 10%	9,612	–	6,857	–	51,512	–	67,981
Discounted future net cash flows	$ 7,246	$ –	$ 6,288	$ –	$ 47,750	$ –	$ 61,284
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 38,974	$ 25,371	$14,472	$ 26,926	$ 65,693	$ 4,086	$ 175,522
Consolidated Subsidiaries							
As of December 31, 2011							
Future cash inflows from sales of oil and gas	$264,991	$280,991	$71,847	$179,337	$203,007	$86,456	$1,086,629
Future production costs	105,391	98,135	15,045	36,309	43,442	23,381	321,703
Future development costs	31,452	35,121	11,987	15,384	16,010	10,052	120,006
Future income tax expenses	53,507	34,542	32,004	67,256	79,975	17,287	284,571
Future net cash flows	$ 74,641	$113,193	$12,811	$ 60,388	$ 63,580	$35,736	$ 360,349
Effect of discounting net cash flows at 10%	42,309	79,303	3,525	22,029	38,066	22,873	208,105
Discounted future net cash flows	$ 32,332	$ 33,890	$ 9,286	$ 38,359	$ 25,514	$12,863	$ 152,244
Equity Companies							
As of December 31, 2011							
Future cash inflows from sales of oil and gas	$ 37,398	$ –	$88,417	$ –	$324,283	$ –	$ 450,098
Future production costs	6,862	–	62,377	–	104,040	–	173,279
Future development costs	3,072	–	2,701	–	3,636	–	9,409
Future income tax expenses	–	–	9,035	–	76,825	–	85,860
Future net cash flows	$ 27,464	$ –	$14,304	$ –	$139,782	$ –	$ 181,550
Effect of discounting net cash flows at 10%	15,941		7,131		71,918		94,990
Discounted future net cash flows	$ 11,523	$ –	$ 7,173	$ –	$ 67,864	$ –	$ 86,560
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 43,855	$ 33,890	$16,459	$ 38,359	$ 93,378	$12,863	$ 238,804

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $19,834 million in 2010 and $27,568 million in 2011, in which there is a 30.4 percent noncontrolling interest.

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

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

Consolidated and Equity Interests	2009		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2008	$ 40,569	$ 45,449	$ 86,018
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	2,138	280	2,418
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	(35,384)	(10,288)	(45,672)
Development costs incurred during the year	13,549	1,017	14,566
Net change in prices, lifting and development costs	51,627	9,245	60,872
Revisions of previous reserves estimates	8,805	858	9,663
Accretion of discount	6,943	5,214	12,157
Net change in income taxes	(22,401)	(2,465)	(24,866)
Total change in the standardized measure during the year	$ 25,277	$ 3,861	$ 29,138*(1)(2)*
Discounted future net cash flows as of December 31, 2009	$ 65,846	$ 49,310	$115,156

(1) Discounted future net cash flows associated with synthetic oil reserves and bitumen mining operations in 2009 were $5,268 million. Cold Lake bitumen operations had been included in discounted future net cash flows in previous years as an oil and gas operation.

(2) The estimated impact of adopting the reliable technology definition and changing from year-end price to first-day-of-the-month average prices in the Securities and Exchange Commission's Rule 4-10 of Regulation S-X was de minimis on discounted future net cash flows for consolidated and equity subsidiaries in 2009.

Consolidated and Equity Interests	2010		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2009	$ 65,846	$ 49,310	$115,156
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	20,093	210	20,303
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	(46,078)	(16,050)	(62,128)
Development costs incurred during the year	20,975	843	21,818
Net change in prices, lifting and development costs	61,612	23,135	84,747
Revisions of previous reserves estimates	14,770	3,605	18,375
Accretion of discount	10,399	5,775	16,174
Net change in income taxes	(33,379)	(5,544)	(38,923)
Total change in the standardized measure during the year	$ 48,392	$ 11,974	$ 60,366
Discounted future net cash flows as of December 31, 2010	$114,238	$ 61,284	$175,522

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

Consolidated and Equity Interests (continued)

	2011		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2010	$114,238	$ 61,284	$175,522
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	6,608	309	6,917
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	(58,308)	(22,402)	(80,710)
Development costs incurred during the year	22,843	1,153	23,996
Net change in prices, lifting and development costs	79,435	46,304	125,739
Revisions of previous reserves estimates	10,462	3,127	13,589
Accretion of discount	16,802	7,196	23,998
Net change in income taxes	(39,836)	(10,411)	(50,247)
Total change in the standardized measure during the year	$ 38,006	$ 25,276	$ 63,282
Discounted future net cash flows as of December 31, 2011	$152,244	$ 86,560	$238,804

OPERATING SUMMARY (unaudited)

	2011	2010	2009	2008	2007
	(thousands of barrels daily)				
Production of crude oil, natural gas liquids, synthetic oil and bitumen					
Net production					
United States	423	408	384	367	392
Canada/South America	252	263	267	292	324
Europe	270	335	379	428	480
Africa	508	628	685	652	717
Asia	808	730	607	599	629
Australia/Oceania	51	58	65	67	74
Worldwide	2,312	2,422	2,387	2,405	2,616
	(millions of cubic feet daily)				
Natural gas production available for sale					
Net production					
United States	3,917	2,596	1,275	1,246	1,468
Canada/South America	412	569	643	640	808
Europe	3,448	3,836	3,689	3,949	3,810
Africa	7	14	19	32	26
Asia	5,047	4,801	3,332	2,870	2,883
Australia/Oceania	331	332	315	358	389
Worldwide	13,162	12,148	9,273	9,095	9,384
	(thousands of oil-equivalent barrels daily)				
Oil-equivalent production *(1)*	4,506	4,447	3,932	3,921	4,180
	(thousands of barrels daily)				
Refinery throughput					
United States	1,784	1,753	1,767	1,702	1,746
Canada	430	444	413	446	442
Europe	1,528	1,538	1,548	1,601	1,642
Asia Pacific	1,180	1,249	1,328	1,352	1,416
Other Non-U.S.	292	269	294	315	325
Worldwide	5,214	5,253	5,350	5,416	5,571
Petroleum product sales *(2)*					
United States	2,530	2,511	2,523	2,540	2,717
Canada	455	450	413	444	461
Europe	1,596	1,611	1,625	1,712	1,773
Asia Pacific and other Eastern Hemisphere	1,556	1,562	1,588	1,646	1,701
Latin America	276	280	279	419	447
Worldwide	6,413	6,414	6,428	6,761	7,099
Gasoline, naphthas	2,541	2,611	2,573	2,654	2,850
Heating oils, kerosene, diesel oils	2,019	1,951	2,013	2,096	2,094
Aviation fuels	492	476	536	607	641
Heavy fuels	588	603	598	636	715
Specialty petroleum products	773	773	708	768	799
Worldwide	6,413	6,414	6,428	6,761	7,099
	(thousands of metric tons)				
Chemical prime product sales					
United States	9,250	9,815	9,649	9,526	10,855
Non-U.S.	15,756	16,076	15,176	15,456	16,625
Worldwide	25,006	25,891	24,825	24,982	27,480

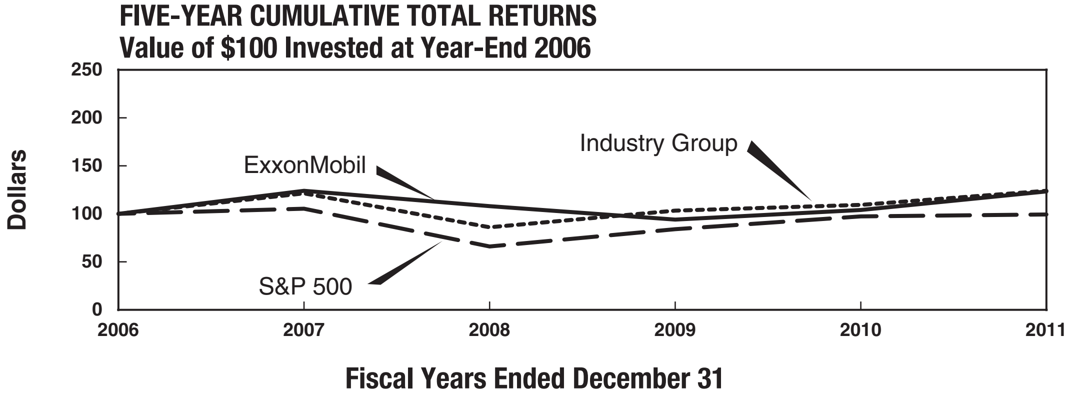
Operating statistics include 100 percent of operations of majority-owned subsidiaries; for other companies, crude production, gas, petroleum product and chemical prime product sales include ExxonMobil's ownership percentage and refining throughput includes quantities processed for ExxonMobil. Net production 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.

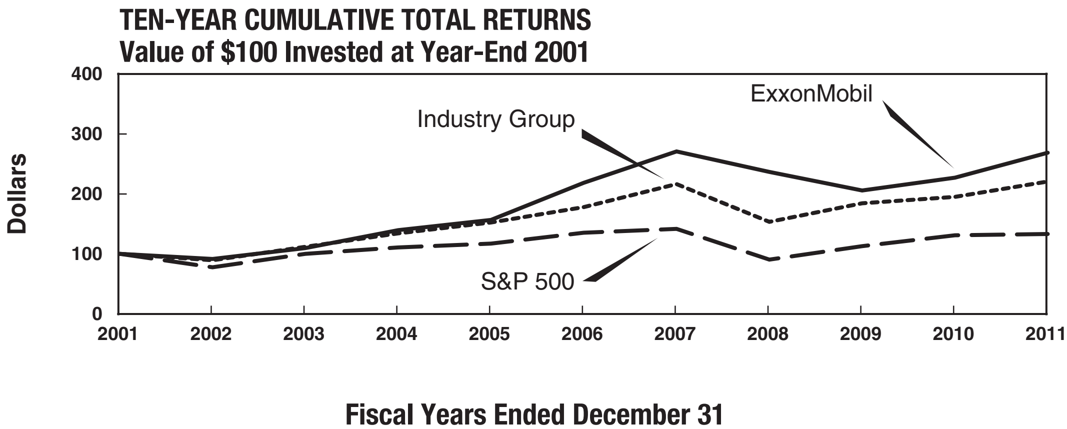
(2) Petroleum product sales data reported net of purchases/sales contracts with the same counterparty.

STOCK PERFORMANCE GRAPHS (unaudited)

Annual total returns to ExxonMobil shareholders were (-13) percent in 2009, 10 percent in 2010, and 19 percent in 2011, and have averaged over 4 percent per year over the past five years. 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 three other international integrated oil companies: BP, Chevron, and Royal Dutch Shell.



ExxonMobil	100	124	108	94	104	123
S&P 500	100	105	66	84	97	99
Industry Group	100	121	86	103	109	124



ExxonMobil	100	91	110	140	157	218	271	236	206	227	269
S&P 500	100	78	100	111	117	135	142	90	113	131	133
Industry Group	100	89	112	134	152	178	216	153	184	195	221

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