FORM 10-K

Annual report pursuant to section 13 and 15(d)

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FILER

MARATHON OIL CORP
CIK:**101778**| IRS No.: **250996816** | State of Incorp.:**DE** | Fiscal Year End: **1231**
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2012

Commission file number 1-5153

Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

Delaware	**25-0996816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5555 San Felipe Street, Houston, TX 77056-2723
(Address of principal executive offices)
(713) 629-6600
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of Common Stock held by non-affiliates as of June 29, 2012: $17,991 million. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers to be affiliates.

There were 707,709,281 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2013.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2013 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

MARATHON OIL CORPORATION

Unless the context otherwise indicates, references to "Marathon Oil," "we," "our" or "us" in this Annual Report on Form 10-K are references to Marathon Oil Corporation, including its wholly-owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest).

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Definitions

Throughout this report, the following company or industry specific terms and abbreviations are used.

AECO – Alberta Energy Company, a Canadian natural gas benchmark price.

AMPCO – Atlantic Methanol Production Company LLC, a company in which we own a 45 percent equity interest.

AOSP – Athabasca Oil Sands Project, an oil sands mining, transportation and upgrading joint venture located in Alberta, Canada, in which we hold a 20 percent interest.

bbl – One stock tank barrel, which is 42 United States gallons liquid volume.

bbld – Barrels per day.

bboe – Billion barrels of oil equivalent. Natural gas is converted to a barrel of oil equivalent based on the energy equivalent, which on a dry gas basis is six thousand cubic feet of gas per one barrel of oil equivalent.

bcf – Billion cubic feet.

boe – Barrels of oil equivalent.

boed – Barrels of oil equivalent per day.

BOEMRE – United States Bureau of Ocean Energy Management, Regulation and Enforcement.

btu – British thermal unit, an energy equivalence measure.

DD&A – Depreciation, depletion and amortization.

Developed acreage – The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development well – A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Downstream business – The refining, marketing and transportation (RM&T) operations, spun-off June 30, 2011 and now treated as discontinued operations.

Drilling Moratorium – As a result of an explosion and significant spill from a deepwater rig in the Gulf of Mexico, the United States Department of the Interior issued a drilling moratorium on May 30, 2010 to suspend the drilling of deepwater wells, and prohibit drilling any new deepwater wells. The moratorium was lifted on October 12, 2010.

Dry well – A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion.

E.G. – Equatorial Guinea.

EGHoldings – Equatorial Guinea LNG Holdings Limited, an liquefied natural gas production company located in E.G. in which we own a 60 percent equity interest.

E&P – Our Exploration and Production segment which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.

EPA – Environmental Protection Agency.

Exit rate – The average daily rate of production from a well or group of wells in the last month of the period stated.

Exploratory well – A well drilled to find oil or gas in an unproved area or find a new reservoir in a field previously found to be productive in another reservoir.

Farmout – An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

FASB – Financial Accounting Standards Board.

FPSO – Floating production, storage and offloading vessel.

IFRS – International Financial Reporting Standards.

IG – Our Integrated Gas segment which produces and markets products manufactured from natural gas, such as liquefied natural gas and methanol, in E.G.

IRS – United States Internal Revenue Service.

KRG – Kurdistan Regional Government.

Liquid hydrocarbon – Collectively, crude oil, condensate and natural gas liquids.

LNG – Liquefied natural gas.

LPG – Liquefied petroleum gas.

Marathon – The consolidated company prior to the June 30, 2011 spin-off of the downstream business.

Marathon Oil – The company as it exists following the June 30, 2011 spin-off of the downstream business.

Marathon Petroleum Corporation ("MPC") – The separate independent company which now owns and operates the downstream business.

mbbl – Thousand barrels.

mbbld – Thousand barrels per day.

mboe – Thousand barrels of oil equivalent.

mboed – Thousand barrels oil equivalent per day.

mcf – Thousand cubic feet.

mmbbl – Million barrels.

mmboe – Million barrels of oil equivalent.

mmbtu – Million British thermal units.

mmcfd – Million cubic feet per day.

mmt – Million metric tonnes.

mmta – Million metric tonnes per annum.

mtd – Thousand metric tonnes per day.

Net acres or Net wells – The sum of the fractional working interests owned by us in gross acres or gross wells.

NGL or NGLs – Natural gas liquid or natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, that can be collectively removed from produced natural gas, separated into these substances and sold.

OECD – Organization for Economic Cooperation and Development.

Oklahoma Resource Basins – Areas in Oklahoma including the Anadarko Woodford shale, the Mississippi Sooner lime, the Granite wash, the Tonkawa, the Cleveland, and the Marmaton plays.

OPEC – Organization of Petroleum Exporting Countries.

OSM – Our Oil Sands Mining segment which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

Productive well – A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved reserves – Proved oil, natural gas and synthetic crude oil reserves are those quantities of oil, natural gas and synthetic crude oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible.

Proved developed reserves – Proved reserves that can be 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.

Proved undeveloped reserves – Proved reserves 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.

PSC – Production sharing contract.

Quest CCS – Quest Carbon Capture and Storage project at the AOSP in Alberta, Canada.

Reserve replacement ratio – A ratio which measures the amount of proved reserves added to our reserve base during the year relative to the amount of oil and gas produced.

Royalty interest – An interest in an oil or natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SAGE – United Kingdom Scottish Area Gas Evacuation system composed of a pipeline and processing terminal.

SAR or SARs – Stock appreciation right or stock appreciation rights.

SEC – United States Securities and Exchange Commission.

Seismic – An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures and 4-D factors in changes that occurred over time).

Total depth ("TD") – The bottom of a drilled hole, where drilling is stopped, logs are run and casing is cemented.

Total proved reserves – The summation of proved developed reserves and proved undeveloped reserves.

U.K. – United Kingdom.

Undeveloped acreage – Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

U.S. – United States of America.

U.S. GAAP – Accounting principles generally accepted in the U.S.

WCS – Western Canadian Select, an oil index benchmark price.

Working interest ("WI") – The interest in a mineral property which gives the owner that share of production from the property. A working interest owner bears that share of the costs of exploration, development and production in return for a share of production. Working interests are typically burdened by overriding royalty interest or other interests.

WTI – West Texas Intermediate crude oil, an oil index benchmark price.

Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. These statements typically contain words such as "anticipate," "believe," "estimate," "expect," "forecast," "plan," "predict," "target," "project," "could," "may," "should," "would" or similar words, indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements in this Annual Report on Form 10-K may include, but are not limited to: levels of revenues, income from operations, net income or earnings per share; levels of capital, exploration, environmental or maintenance expenditures; the success or timing of completion of ongoing or anticipated capital, exploration or maintenance projects; volumes of production or sales of liquid hydrocarbons, natural gas, and synthetic crude oil; levels of worldwide prices of liquid hydrocarbons and natural gas; levels of liquid hydrocarbon, natural gas and synthetic crude oil reserves; the acquisition or divestiture of assets; the effect of restructuring or reorganization of business components; the potential effect of judicial proceedings on our business and financial condition; levels of common share repurchases; the impact of government legislation and budgetary and tax measures; and the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local governments and regulatory authorities.

PART I

Item 1. Business

General

Marathon Oil Corporation was incorporated in 2001 and is an international energy company engaged in exploration and production, oil sands mining and integrated gas with operations in the U.S., Angola, Canada, E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq, Libya, Norway, Poland and the U.K. We are based in Houston, Texas with our corporate headquarters at 5555 San Felipe Street, Houston, Texas 77056-2723 and a telephone number of (713) 629-6600.

On June 30, 2011, the spin-off of Marathon's downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. Marathon stockholders at the close of business on the record date of June 27, 2011 received one share of MPC common stock for every two shares of Marathon common stock held. A private letter ruling received in June 2011 from the IRS affirmed the tax-free nature of the spin-off. Activities related to the downstream business have been treated as discontinued operations in 2011 and 2010, with additional information in Item 8. Financial Statements and Supplementary Data - Note 3 to the consolidated financial statements.

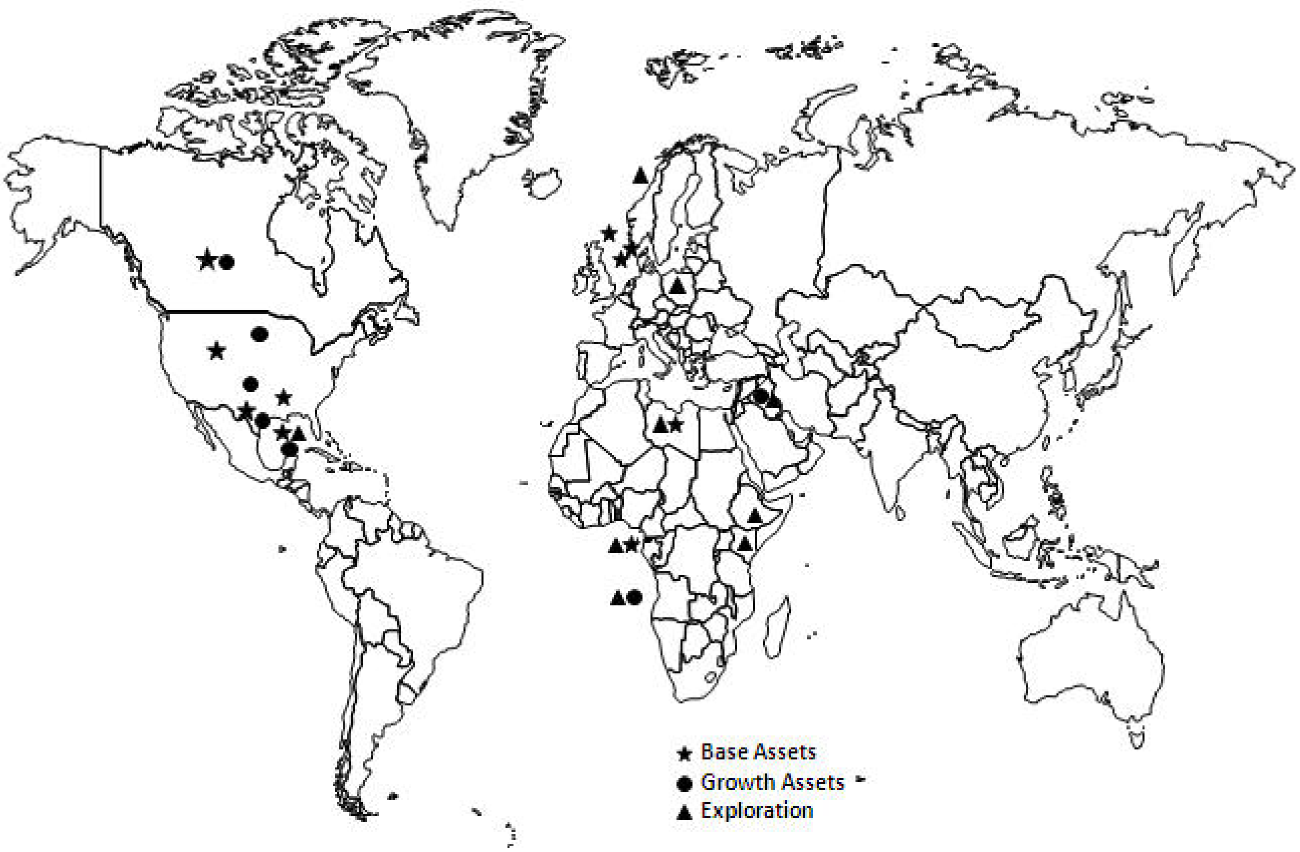
Strategy and Results Summary

Assets within our three segments are at various stages in their lifecycle: base, growth or exploration. We have a stable group of base assets, which include our OSM and IG segments and E&P assets in E.G., Libya, Norway, the U.K. and certain U.S. operations. These assets generate much of the cash that will be available for investment in our growth assets and exploration projects. Growth assets are where we expect to make significant investment in order to realize oil and gas production and reserve increases. We are focused on U.S. liquid hydrocarbon growth by developing unconventional liquids-rich plays, including the Eagle Ford and Bakken shales, and the Oklahoma Resource Basins. In addition to the U.S. shale plays, growth assets include deepwater discoveries and developments offshore Angola, our Canadian in-situ assets, certain Gulf of Mexico blocks and the Kurdistan Region of Iraq. We also invest in exploration prospects that have significant value potential. Our areas of exploration are E.G., Ethiopia, Gabon, the Gulf of Mexico, Kenya, the Kurdistan Region of Iraq, Libya, Norway and Poland. We continually evaluate ways to optimize our portfolio through acquisitions and divestitures, with a previously stated goal of divesting between $1.5 billion and $3.0 billion of non-core assets over the period of 2011 through 2013. For the two-year period ended December 31, 2012, we entered into agreements for approximately $1.3 billion in divestitures, of which $785 million were completed. The remaining $545 million in asset sales were completed by February 22, 2013.

We ended 2012 with proved reserves of 2 bboe, a 12 percent increase over 2011. Average sales volumes were 282 mbbld of liquid hydrocarbon, 902 mmcfd of natural gas and 47 mbbld of synthetic crude oil, with 62 percent of our liquid hydrocarbon sales volumes from international operations, for which average realizations have exceeded WTI crude prices. During 2012, we invested in the development of assets totaling $5.4 billion in capital, investment and exploration spending and made acquisitions of approximately $1 billion. We expect continued spending, primarily funded with cash flow from operations or portfolio optimization, in exploration and development activities in order to realize continued reserve and sales growth. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Outlook, for discussion of our $5.2 billion capital, investment and exploration budget for 2013.

The above discussion of strategy and results includes forward-looking statements with respect to the goal of divesting between $1.5 billion and $3.0 billion of non-core assets between 2011 and 2013 and expected investment in exploration and development activities. Some factors that could potentially affect the divestiture of non-core assets and expected investment in exploration and development activities include changes in prices of and demand for liquid hydrocarbons, natural gas and synthetic crude oil, actions of competitors, occurrence of acquisitions or dispositions of oil and natural gas properties, future financial condition, operating results, economic and/or regulatory factors affecting our businesses, the identification of buyers for non-core assets and the negotiation of acceptable prices and other terms, as well as other customary closing conditions. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

The map below illustrates the locations of our worldwide operations.



Segment and Geographic Information

For operating segment and geographic financial information, see Item 8. Financial Statements and Supplementary Data – Note 8 to the consolidated financial statements.

Exploration and Production Segment

In the discussion that follows regarding our E&P operations, references to net wells, sales or investment indicate our ownership interest or share, as the context requires.

We are engaged in oil and gas exploration, development and/or production activities in the U.S., Angola, Canada, Ethiopia, E.G., Gabon, Kenya, the Kurdistan Region of Iraq, Libya, Norway, Poland, and the U.K.

Liquids-Rich Shale Plays

Eagle Ford - As of December 31, 2012 we have 230,000 net acres in the core of the Eagle Ford shale, with an additional 100,000 non-core acres. In the fourth quarter of 2011, we made our most significant investment in the Eagle Ford shale play of south Texas when we closed several acquisitions for a total cash consideration of $4.5 billion. Throughout 2012, we rationalized our position with several acquisitions totaling $1 billion and select divestitures of acreage located outside the core of the Eagle Ford shale. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for additional information about these acquisitions.

As of December 31, 2012, we had 379 gross (262 net) producing wells in the Eagle Ford shale. We realized significant efficiencies in drilling during 2012, reducing the average drilling time per well to 23 days, reaching TD on 248 gross (178 net)operated wells and brought 215 gross (154 net) operated wells to sales. Approximately one-third of our 2013 capital budget is dedicated to the Eagle Ford shale. Our plans include drilling and completing 275 - 320 gross (215 - 250 net) operated wells in 2013. We have undertaken a number of pilot tests across the acreage to assist in identifying appropriate spacing, landing zones and completion techniques for the Eagle Ford. Results from vertical landing zone pilots and completions pilots are ongoing and incorporated into operations continuously. Initial analysis of spacing pilot results are expected by the end of 2013 and may result in improvements to our overall development plans for the field.

Eagle Ford average net sales for 2012 were 34 mboed, composed of 23 mbbld of crude oil, 5 mbbld of NGLs and 37 mmcfd of natural gas. Our 2012 exit rate of production was over 65 mboed, which is fourfold increase over December 2011. We are able to transport approximately 60 percent of our Eagle Ford production by pipeline and additional contract negotiations and facility designs are underway.

We continue to build infrastructure to support our liquid hydrocarbon and natural gas production growth across the operating area. Approximately 370 miles of gathering lines were installed in 2012, and 12 new central gathering and treating facilities were commissioned, with 7 additional facilities in various stages of planning or construction. We also own and operate the Sugarloaf gathering system, a 42-mile natural gas pipeline through the heart of our acreage in Karnes, Atascosa, and Bee Counties of south Texas.

Bakken – We hold approximately 410,000 net acres in the Bakken shale oil play in North Dakota and eastern Montana. Throughout 2012, we continued selective acreage acquisitions and leasing, further expanding a new prospect area. We moved from 20-stage to 30-stage hydraulic fracturing in 2011 to increase both production rates and estimated ultimate recovery from our Bakken shale wells. We also continued to alter completion techniques seeking continuous improvement in well performance. We reached TD on 88 gross (76 net) operated wells and brought to sales 98 gross (84 net) operated wells in 2012. Our Bakken shale program includes plans to drill 190 - 220 gross (65 - 70 net) wells in 2013, of which 60 - 70 net wells will be operated by us.

Our net sales from the Bakken shale averaged 29 mboed, composed of 27 mbbld of crude oil, 1 mbbld NGLs and 8 mmcfd natural gas in 2012, a 70 percent increase on a barrel of oil equivalent basis over 2011. Our production exit rate for 2012 was approximately 35 mboed. We sell our Bakken production into various markets via truck, railcar and other marketing options. We have, and continue to secure, long-term agreements to transport portions of our current and forecasted liquid hydrocarbon production to market via third-party gathering systems.

Oklahoma Resource Basins – In the Anadarko Woodford shale play in Oklahoma, we hold 163,000 net acres of which approximately 100,000 net acres are held by production. In 2012, we executed an operated drilling program focused on the liquids-rich areas of the play, reached TD on 25 gross (20 net) operated wells and brought to sales 29 gross (25 net) operated wells. In 2013, we plan to drill 42 - 50 gross (15 - 19 net) wells, of which 12 - 14 net wells will be operated. The Anadarko Woodford shale averaged net sales of 8 mboed, composed of 1 mbbld of crude oil, 2 mbbld of NGLs and 29 mmcfd of natural gas, during 2012, a more than threefold increase over 2011 on a barrel of oil equivalent basis. Our 2012 exit rate of production was 10 mboed.

Other areas of potential growth exist in Oklahoma and we are currently evaluating opportunities on legacy assets where the acreage is held by production. Future activity in the Oklahoma Resource Basins will be dependent upon the recovery of natural gas and natural gas liquids prices. See below for additional discussion of our conventional, primarily natural gas, production operations in Oklahoma.

United States

Alaska – In April 2012, we entered into an agreement to sell all of our assets in Alaska in a transaction valued at $375 million before closing adjustments. Those assets include operated and non-operated interests in 10 natural gas fields in the Cook Inlet and adjacent Kenai Peninsula of Alaska and majority ownership in four operated natural gas pipelines totaling 140 miles. The transaction closed in January 2013 for proceeds of $195 million subject to a six-month escrow of $50 million for various indemnities. Net sales from Alaska averaged 92 mmcfd in 2012.

Colorado – We hold leases with natural gas production in the Piceance Basin of Colorado, located in the Greater Grand Valley field complex and 154,000 net acres in the liquids-rich Niobrara shale located in the DJ Basin of northern Colorado, southeastern Wyoming and Nebraska. We drilled 17 gross (12 net) operated wells in the DJ Basin during 2012. Net sales from these two areas averaged 3 mboed in 2012. We have no plans for operated drilling in Colorado in 2013.

Oklahoma – We have long-established operated and non-operated conventional production in several Oklahoma fields from which 2012 sales averaged 2 mbbld of liquid hydrocarbons and 51 mmcfd of natural gas. In 2012, we participated in 11 gross (1 net), non-operated wells in the state. We also drilled 1 operated well. Plans for 2013 include drilling 11 gross (2 net) wells, targeting liquids.

Texas/North Louisiana/New Mexico – In east Texas and north Louisiana, we hold 184,000 net acres. Approximately 20,000 of the acres are in the Haynesville and Bossier natural gas shale plays. Most of the acreage in these shale plays is held by production. We participated in 5 gross (1 net) non-operated wells in the area during 2012. Conventional production was primarily from the Mimms Creek, Pearwood and Oletha fields in 2012, with net sales averaging 6 mboed.

We also participate in several non-operated Permian Basin fields in west Texas and New Mexico. Net sales from this area averaged 7 mboed in 2012. We plan continued carbon dioxide flood programs in the Seminole and Vacuum fields during 2013.

Wyoming – We have ongoing enhanced oil recovery waterflood projects at the mature Bighorn Basin and Wind River Basin fields and initiated an additional enhanced oil recovery project at our 100 percent owned and operated Pitchfork field in 2012. We have conventional natural gas operations in the Greater Green River Basin and unconventional coal bed natural gas operations in the Powder River Basin. In 2012, we drilled 2 gross (2 net) operated development wells in Wyoming, which included 1 wellbore re-entry. We plan to drill 1 gross (1 net) operated well in 2013.

Our Wyoming net sales averaged 17 mbbld of liquid hydrocarbons and 68 mmcfd of natural gas during 2012. In addition, we own and operate the 420-mile Red Butte Pipeline. This crude oil pipeline connects Silvertip Station on the Montana/Wyoming state line to Casper, Wyoming.

Over the next two years, we plan to plug and abandon over 600 wells in the Powder River Basin as we wind down those operations due to poor economics. See Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements for impairments of our Powder River Basin asset taken in recent years due to declining natural gas prices and reduced development plans.

Gulf of Mexico – Production

On December 31, 2012, we held material interests in 7 producing fields, 4 of which are company-operated. Average net sales for 2012 from the Gulf of Mexico were 22 mbbld of liquid hydrocarbons and 19 mmcfd of natural gas.

We operate and have a 65 percent working interest in the Ewing Bank Block 873 platform which is located 130 miles south of New Orleans, Louisiana. The platform serves as a production hub for the Lobster, Oyster and Arnold fields on Ewing Bank blocks 873, 917 and 963. The facility also processes third-party production via subsea tie-backs. In 2012, seismic data that was acquired in 2011 on Blocks 873 and 917 was processed in order to refine existing opportunities and to identify others for a development drilling campaign that is planned to start in 2015.

We own a 50 percent working interest in the non-operated Petronius field on Viosca Knoll Blocks 786 and 830 located 130 miles southeast of New Orleans, which includes 14 producing wells. The Petronius platform is capable of providing processing and transportation services to nearby third-party fields. During 2012, we acquired 4-D seismic data in order to identify potential future drilling opportunities.

We hold a 30 percent working interest in the non-operated Neptune field located on Atwater Valley Block 575, 120 miles off the coast of Louisiana. The development includes seven subsea wells tied back to a stand-alone platform. A well that had been producing from a deeper horizon was recompleted to the main producing zone in 2012.

The Droshky and Ozona developments off the coast of Louisiana are both expected to reach abandonment pressures in the first half of 2013. We have a 100 percent operated working interest in the Droshky development located on Green Canyon Block 244 and a 68 percent operated working interest in Ozona which is located on Garden Banks Block 515.

In February 2013, we sold our 34 percent non-operated interest in the Neptune gas plant that is located onshore Louisiana. The transaction value, before closing adjustments, was $170 million.

Gulf of Mexico – Exploration

We have a portfolio of over 18 prospects with multiple drilling opportunities in the Gulf of Mexico. As we evaluate these opportunities for drilling, we plan to seek partners to reduce our exploration risk on individual projects.

A successful deepwater oil discovery well was drilled on the Gunflint prospect, located on Mississippi Canyon Block 948, in 2008. We own a 15 percent non-operated working interest in this prospect. One appraisal well was drilled in 2012 confirming expected reservoir properties and establishing the commercial viability of the field. An additional appraisal well began drilling in February 2013. Development planning is ongoing.

In the first quarter of 2009, we participated in a deepwater oil discovery on the Shenandoah prospect located on Walker Ridge Block 52. We own a 10 percent interest in this non-operated prospect. The first appraisal well began drilling in June 2012, has reached TD and is currently being evaluated.

In the third quarter of 2012, we resumed drilling an exploratory well on the Innsbruck prospect located on Mississippi Canyon Block 993 which had been temporarily suspended under the federal government's Drilling Moratorium. Upon reaching TD in November 2012, the well was determined to be dry. The well costs and related unproved property costs were charged to exploration expense in 2012. We have a 45 percent operated working interest in Innsbruck.

We hold a 30 percent non-operated working interest in Green Canyon Blocks 403 and 404 in the Kilchurn prospect. The operator commenced drilling in the Kilchurn prospect in December 2011. In the second quarter of 2012, the well was determined to be dry. The well costs and related unproved property costs were charged to exploration expense in 2012.

In October 2011, we received approval of an exploration plan from the BOEMRE for the Key Largo prospect located on Walker Ridge Block 578. We have a 60 percent working interest and are the operator of this prospect. Drilling is expected in 2014.

We currently hold a 100 percent operated working interest in the Madagascar prospect located on DeSoto Canyon Block 757. Our exploration plan was approved by the BOEMRE in 2012. We expect to drill the first exploration well on the prospect in 2013 at a lower working interest.

Africa

Equatorial Guinea - We own a 63 percent operated working interest under a PSC in the Alba field which is offshore E.G. During 2012, E.G. net liquid hydrocarbon sales averaged 36 mbbld, and net natural gas sales averaged 428 mmcfd. Operational availability for 2012 averaged 95 percent.

We hold a 63 percent operated working interest in the Deep Luba discovery on the Alba Block and an 80 percent operated working interest in the Corona well on Block D. We plan to develop Block D through a unitization with the Alba field, which is expected in late 2013 or early 2014.

We have an 80 percent operated working interest in exploratory Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field.

We also own a 52 percent interest in Alba Plant LLC, an equity method investee that operates an onshore LPG processing plant located on Bioko Island. Alba field natural gas is processed by the LPG plant. Under a long-term contract at a fixed price per btu, the LPG plant extracts secondary condensate and LPG from the natural gas stream and uses some of the dry natural gas in its operations. During 2012, the gross quantity of natural gas supplied to the LPG production facility was 863 mmcfd, and 7 mbbld of secondary condensate and 20 mbbld of LPG were produced by Alba Plant LLC. Our share of the income ultimately generated by the subsequent export of secondary condensate and LPG produced by Alba Plant LLC is reflected in our E&P segment.

As part of our IG segment, we own 45 percent of AMPCO and 60 percent of EGHoldings, both of which are accounted for as equity method investments. AMPCO operates a methanol plant and EGHoldings operates an LNG production facility, both located on Bioko Island. Dry natural gas from the Alba field, which remains after the condensate and LPG are removed by Alba Plant LLC, is supplied to both of these facilities under long-term contracts at fixed prices. Because of the location of and limited local demand for natural gas in E.G., we consider the prices under the contracts with Alba Plant LLC, AMPCO and EGHoldings to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. Our share of the income ultimately generated by the subsequent export of methanol produced by AMPCO and LNG produced by EGHoldings is reflected in our IG segment as discussed below. During 2012, the gross quantities of dry natural gas supplied to the methanol plant to the LNG production facility were 119 mmcfd and 639 mmcfd. Any remaining dry gas is returned offshore and reinjected into the Alba field for later production.

Libya - We hold a 16 percent working interest in the Waha concessions, which encompass almost 13 million acres located in the Sirte Basin of eastern Libya. During the first quarter of 2011, all production operations in Libya were suspended due to civil unrest. In the fourth quarter of 2011, limited production resumed from the Waha concessions, but we made no deliveries of hydrocarbons. Sales resumed in the first quarter of 2012 and averaged 45 mboed in 2012.

Angola – Offshore Angola, we hold 10 percent working interests in Blocks 31 and 32, both of which are non-operated. The discoveries on Blocks 31 and 32 represent several potential development hubs. In 2008, we received approval to proceed with the first deepwater development project, called the PSVM development, which includes the Plutao, Saturno, Venus and Marte discoveries and one successful appraisal well in the northeastern portion of Block 31. The PSVM development utilizes a FPSO with a total of 48 production and injection wells. Development drilling began in 2010 and first production was in the fourth quarter of 2012, with first sales in February 2013. Our plans include continued development drilling with tie-in to the FPSO in order to reach a production plateau of 14 net mboed in the first half of 2014 which is expected to last through 2017.

Front-end engineering and design for the Kaombo development, located in the southeastern portion of Block 32, is underway. The development is expected to consist of two-105 mbbld FPSO. Project sanction is expected mid-2013 so that production from the Kaombo development is possible in 2016. We continue to assess other discoveries on Blocks 31 and 32 for development potential.

Gabon - We hold a 21 percent non-operated working interest in the Diaba License G4-223 and its related permit offshore Gabon, which covers 2.2 million gross (467,500 net) acres. The start of exploration drilling is expected in the first quarter of 2013.

Kenya - We hold a 50 percent non-operated working interest in Block 9 and a 15 percent non-operated working interest in Block 12A which are located in northwest Kenya, covering 12.3 million gross (4.4 million net) acres. Seismic has been acquired on Block 9 and seismic acquisition on Block 12A is underway. The first exploratory well is expected to begin drilling on Block 9 in the second quarter of 2013. We have the right to assume the role of operator on Block 9 if a commercial discovery is made.

Ethiopia - In January 2013, government approval was received for our acquisition of a 20 percent non-operated interest in the onshore South Omo concession in Ethiopia. The concession has an area of approximately 7.3 million gross (1.5 million net) acres. The Sabisa 1 exploration well began drilling in January 2013 and is expected to take approximately 60 days to reach the planned TD of 8,500 ft.

Europe

Norway – At the end of 2012, we operated 10 licenses and held interests in six non-operated licenses, which encompass approximately 240,000 net acres on the offshore Norwegian continental shelf. In 2012, net sales from Norway averaged 81 mbbld of liquid hydrocarbons and 53 mmcfd of natural gas.

The Alvheim development is comprised of the Kameleon, East Kameleon and Kneler fields (PL 036C, PL 088BS and PL 203), in each of which we have a 65 percent working interest, and the Boa field, in which we have a 58 percent working interest. It is produced to the Alvheim complex which consists of a FPSO with subsea infrastructure. In 2011 and 2012, due to debottlenecking efforts, capacity of the FPSO increased by 15 mbbld gross. Peak oil production of 157 mbbld gross (94 mbbld net) was reached in the first quarter of 2012. During 2012 operational availability of the Alvheim development was 96 percent including planned maintenance activities, while unplanned downtime was minimal at 3 percent. Produced oil is transported by shuttle tanker and produced natural gas is transported to the SAGE system by pipeline. At the end of 2012, the Alvheim development included 14 producing wells and 2 water disposal wells.

In October 2012, we took over operatorship of the nearby Vilje field (PL 036D), in which we own a 47 percent working interest, which began producing through the Alvheim complex in August 2008. At the end of 2012, 2 wells were producing and an additional development, Vilje Sor, had been approved. Production from Vilje Sor is estimated to begin near the end of 2013.

The Volund field (PL 150 and PL 150BS) is tied back to the Alvheim complex, which is five miles to the north. The Volund development, in which we own a 65 percent operated working interest, consists of three production wells and one water injection well at December 31, 2012. The drilling of an additional development well at Volund was completed in the fourth quarter 2012 and first production commenced in January 2013.

The Viper/Kobra (PL 203) oil discovery, in the immediate vicinity of the Volund Field, was announced in November 2009. We hold a 65 percent operated working interest in Viper/Kobra. Along with our partners, we are evaluating a possible tie-back to the Alvheim complex.

The Boyla field, formerly the Marihone discovery, (PL 340) is located approximately 17 miles south of Alvheim. In October 2012, the Norwegian Ministry of Petroleum and Energy approved the plan for the development and operation of the Boyla field in which we hold a 65 percent operated working interest. First production from Boyla is expected in the fourth quarter of 2014. Near Boyla is the Caterpillar discovery (PL340BS), which was made in 2011. It is being evaluated as a tie-back to the Alvheim complex through Boyla.

Also offshore Norway, the Darwin (formerly Velsemoy) well is expected to begin drilling late in the first quarter of 2013 on PL 531 in which we hold a 10 percent non-operated working interest. Drilling is also expected to commence in the third quarter of 2013 on the Sverdrup well on PL 330 where we hold a 30 percent non-operated working interest.

In January 2013, we were awarded a 20 percent non-operated working interest in PL 694, which consists of three blocks, south of the Sverdrup prospect area, in the Norwegian Sea. We were also awarded additional acreage in the North Sea, north of the Alvheim area in PL 203B. Our 65 percent working interest and role as operator are the same as PL 203. In addition, effective January 2013, we withdrew from two licenses (PL505 and PL505B). In 2013, we will operate 9 licenses and have an interest in approximately 225,000 net acres.

United Kingdom – Net sales from the U.K. averaged 16 mbbld of liquid hydrocarbons and 48 mmcfd of natural gas in 2012. Our largest asset in the U.K. sector of the North Sea is the Brae area complex where we are the operator and have a 42 percent working interest in the South, Central, North and West Brae fields and a 39 percent working interest in the East Brae field. The Brae Alpha platform and facilities host the South, Central and West Brae fields. The North Brae and East Brae fields are natural gas condensate fields which are produced via the Brae Bravo, and the East Brae platform, respectively. The East Brae platform also hosts the nearby Braemar field in which we have a 28 percent working interest. Two development wells were completed at West Brae in early 2011 and we continue to pursue Brae complex projects designed to maximize natural gas recovery and maintain deliverability rates to the U.K. market.

The strategic location of the Brae platforms, along with pipeline and onshore infrastructure, has generated third-party processing and transportation business since 1986. Currently, the operators of twenty-five third-party fields are contracted to use the Brae system and 67 mboed are being processed or transported through the Brae infrastructure. In addition to generating processing and pipeline tariff revenue, this third-party business optimizes infrastructure usage.

The Brae group owns a 50 percent interest in the non-operated SAGE system. The SAGE pipeline transports natural gas from the Brae area, and the third-party Beryl area, and has a total wet natural gas capacity of 1.1 bcf per day. The SAGE terminal at St. Fergus in northeast Scotland processes natural gas from the SAGE pipeline as well as approximately 1 bcf per day of third-party natural gas.

In the U.K. Atlantic Margin west of the Shetland Islands, we own an average 30 percent working interest in the non-operated Foinaven area complex, consisting of a 28 percent working interest in the main Foinaven field, a 47 percent working interest in East Foinaven and a 20 percent working interest in the T35 and T25 fields. The export of Foinaven liquid hydrocarbons is via shuttle tanker from the FPSO to market. All natural gas sales are to the non-operated Magnus platform for use as injection gas. An ongoing upgrade of equipment on the FPSO is expected to extend the life of the fields from 2017 to 2021. Additionally, the planned installation of replacement flowlines should secure the long-term integrity of the subsea infrastructure.

Poland – As of December 31, 2012, we hold a 51 percent working interest in 9 concessions, an 85 percent working interest in one concession and a 100 percent interest in one concession for a total of approximately 1.2 million net acres. We are operator under all licenses. In 2012, we reached TD on 5 gross (3 net) operated wells and in 2013 have reached TD on one more gross (0.85 net) well. Since late 2011, we have conducted a continuous drill, core and diagnostic fluid injection test program ("DFIT"). Following these DFIT evaluations, we plan to hydraulically fracture select wells. We are evaluating all data collected through drilling in addition to proprietary 2-D seismic acquired in 2011, 2012, and 2013.

Canada

We hold interests in both operated and non-operated exploration stage oil sand leases in Alberta, Canada, which would be developed using in-situ methods of extraction. These leases cover approximately 143,000 gross acres (52,000 net) in four project areas: Namur, in which we hold a 60 percent operated interest; Birchwood, in which we hold a 100 percent operated interest; Ells River, in which we hold a 20 percent non-operated interest and Saleski in which we hold a 33 percent non-operated interest.

During the first quarter of 2012, we submitted a regulatory application for a proposed 12 mbbld steam assisted gravity drainage ("SAGD") project at Birchwood. Pending regulatory approval, project sanction is expected in 2014, with first oil projected in 2017. Exploration activities leading up to this application included drilling approximately 100 stratigraphic test wells in the winter of 2010 to 2011 and a 3-D seismic survey in 2012.

Other International

Kurdistan Region of Iraq - In aggregate, we have access to approximately 215,000 net acres in the Kurdistan Region of Iraq. We have interests in two non-operated blocks located north-northwest of Erbil: Atrush, in which our working interest is 20 percent, and Sarsang, in which our working interest is 25 percent. Through December 31, 2012, discoveries have been made in each block and successful appraisal wells were drilled and tested on both blocks during 2012, including the discovery of additional hydrocarbon-bearing zones. Further appraisal and development drilling is planned for 2013. Additional exploration drilling is proceeding on the Sarsang block. Two exploration wells commenced in late 2012 with results expected in the first quarter of 2013. A further exploration well will be drilled during 2013.

The exploration and appraisal work on the Atrush block resulted in a declaration of commerciality being submitted by the operator in November 2012. A field development plan will be submitted for government approval in May 2013. This plan will outline the forward commitments required to develop the field in the most economic way. The multiple prospects on the Sarsang block require additional exploration and appraisal work through 2013.

We also have PSCs for operatorship of the Harir and Safen blocks located northeast of Erbil. After selling down a portion of our interest in the third quarter of 2012 to balance our portfolio, our working interest is 45 percent in each block. We have completed an extensive 2-D seismic program on both blocks. The first exploration well on the Harir block commenced drilling in July 2012, reached TD in December 2012, was tested and deemed to be dry. We plan to start an exploration well on the Safen block and a second exploration well on the Harir block in the first half of 2013.

Acquisitions and Dispositions

We continually evaluate ways to optimize our portfolio through acquisitions and dispositions, with a previously stated goal of divesting between $1.5 billion and $3 billion of non-core assets over the period of 2011 through 2013. For the two-year period ended December 31, 2012, we entered into agreements for approximately $1.3 billion in divestitures, of which $785 million were completed. The remaining $545 million in asset sales were completed by February 22, 2013. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for additional information about the acquisitions and Note 6 for additional information about the dispositions.

Acquisitions

In the second half of 2012, we closed acquisitions of approximately 25,000 net acres in the core of the Eagle Ford shale at transaction values totaling approximately $1 billion before closing adjustments. The acquisitions included wells producing 12 net mboed at closing.

In October 2012, we entered into an agreement to acquire a 20 percent non-operated working interest in the South Omo concession onshore Ethiopia with an effective date of August 17, 2012. Ethiopian government approval was received and this transaction closed in January 2013 for cash consideration of $40 million, before closing adjustments, plus an additional payment of $10 million due upon declaration of a commercial discovery.

In July 2012, we entered into an agreement to acquire non-operated positions in two onshore exploration blocks in northwest Kenya. Upon closing the $32 million transaction in October 2012, we now hold a 50 percent working interest in Block 9 and a 15 percent working interest in Block 12A.

In June 2012, we entered an agreement to acquire a 21 percent non-operated working interest in the Diaba License G4-223 and its related permit onshore Gabon. The transaction closed in October 2012.

During June 2012, we signed a new production sharing contract with the government of E.G. for the exploration of Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field. We have an 80 percent operated working interest in this block. The contract was ratified by the government in the third quarter of 2012. We also acquired an additional interest in Block D, bringing our working interest to 80 percent.

Dispositions

In February 2013, we entered an agreement to convey our interests in the Marcellus natural gas shale play to the operator.

In December 2012, we entered into an agreement to sell our E&P segment's interest in the Neptune gas plant, located onshore Louisiana. The transaction, with a value of $170 million before closing adjustments, closed in February 2013.

In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres located outside the core of the Eagle Ford shale for proceeds of $9 million, recording a loss of $18 million.

In June 2012, we agreed to sell-down our interests in the Harir and Safen blocks in the Kurdistan Region of Iraq. The transaction subsequently closed and we received cash proceeds of $140 million before closing adjustments, so that we now have a 45 percent working interest in each of the two blocks.

In May 2012, we executed agreements to relinquish our operatorships of, and participating interests in, the Bone Bay and Kumawa exploration licenses in Indonesia. Government ratification of the agreements was received during the third quarter of 2012, which released us from our obligations and further commitments related to these licenses.

In April 2012, we entered into an agreement to sell all of our assets in Alaska in a transaction valued at $375 million before closing adjustments. The transaction closed in January 2013 for proceeds of $195 million subject to a six-month escrow of $50 million for various indemnities.

In January 2012, we closed on the sale of our interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This includes our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded in the first quarter of 2012.

The above discussions include forward-looking statements with respect to the timing and levels of future liquid hydrocarbon and natural gas production, anticipated future exploratory and development drilling activity, expectations for improvements to development plans from the optimization of well spacing in the Eagle Ford shale play, planned use of carbon dioxide flood programs, the timing of reaching abandonment pressures for the Droshky and Ozona developments, the expected life extension of the Foinaven fields, the timing of project sanction and first oil from the SAGD project, and the goal of divesting between $1.5 and $3.0 billion of non-core assets over the period of 2011 through 2013. The projected asset dispositions through 2013 are based on current expectations, estimates, and projections and are not guarantees of future performance. Some factors which could possibly affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, drilling rig availability, the inability to obtain or delay in obtaining necessary government and third-party approvals and permits, unforeseen hazards such as weather conditions, natural disasters, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The SAGD project may further be affected by board approval, transportation logistics, availability of materials and labor, and other risks associated with construction projects. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Productive and Drilling Wells

For our E&P segment, the following tables set forth gross and net productive wells and service wells as of December 31, 2012, 2011 and 2010 and drilling wells as of December 31, 2012.

	Productive Wells[a]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2012								
U.S.	6,191	2,315	3,208	1,906	2,328	736	66	30
E.G.	—	—	14	9	4	3	—	—
Other Africa	1,050	171	6	1	101	16	5	1
Total Africa	1,050	171	20	10	105	19	5	1
Total Europe	77	34	40	16	28	11	1	1
Total Other International	—	—	—	—	—	—	4	1
Worldwide	7,318	2,520	3,268	1,932	2,461	766	76	33
2011								
U.S.	5,809	2,058	3,121	1,876	2,313	734		
E.G.	—	—	14	9	4	3		
Other Africa[b]	—	—	—	—	1	—		
Total Africa	—	—	14	9	5	3		
Total Europe	73	31	40	16	28	10		
Worldwide	5,882	2,089	3,175	1,901	2,346	747		
2010								
U.S.	4,818	1,860	3,145	1,905	2,466	746		
E.G.	—	—	13	9	5	3		
Other Africa	1,022	168	3	—	94	16		
Total Africa	1,022	168	16	9	99	19		
Total Europe	71	30	40	16	29	11		
Worldwide	5,911	2,058	3,201	1,930	2,594	776		

[a] Of the gross productive wells, wells with multiple completions operated by us totaled 188, 168 and 164 as of December 31, 2012, 2011 and 2010. Information on wells with multiple completions operated by others is unavailable to us.

[b] As operations were resuming in Libya at December 31, 2011, an accurate count of productive wells was not possible; therefore no Libyan wells are included in this number.

Drilling Activity

For our E&P segment, the following table sets forth, by geographic area, the number of net productive and dry development and exploratory wells completed in each of the last three years.

	Development				Exploratory				Total
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	
2012									
U.S.	172	21	2	195	117	13	9	139	334
Total Africa	4	—	—	4	1	—	—	1	5
Total Europe	3	—	—	3	—	—	—	—	3
Total Other International	—	—	—	—	—	—	—	—	—
Worldwide	179	21	2	202	118	13	9	140	342
2011									
U.S.	46	17	3	66	37	4	1	42	108
Total Africa[a]	2	—	—	2	—	—	—	—	2
Total Europe	2	—	—	2	—	—	—	—	2
Total Other International	—	—	—	—	—	—	1	1	1
Worldwide	50	17	3	70	37	4	2	43	113
2010									
U.S.	35	46	1	82	20	11	3	34	116
Total Africa	5	—	—	5	1	—	—	1	6
Total Europe	2	—	—	2	—	—	—	—	2
Total Other International	—	—	—	—	1	—	1	2	2
Worldwide	42	46	1	89	22	11	4	37	126

[a] Activity in Libya through February 2011.

Acreage

We believe we have satisfactory title to our properties in accordance with standards generally accepted in the industry; nevertheless, we can be involved in title disputes from time to time which may result in litigation. In the case of undeveloped properties, an investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. Our title to properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the industry. In addition, our interests may be subject to obligations or duties under applicable laws or burdens such as net profits interests, liens related to operating agreements, development obligations or capital commitments under international PSCs or exploration licenses.

The following table sets forth, by geographic area, the gross and net developed and undeveloped E&P acreage held in our E&P segment as of December 31, 2012.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,703	1,271	1,298	1,036	3,001	2,307
Canada	—	—	143	55	143	55
Total North America	1,703	1,271	1,441	1,091	3,144	2,362
E.G.	45	29	183	164	228	193
Other Africa	12,922	2,109	16,069	4,856	28,991	6,965
Total Africa	12,967	2,138	16,252	5,020	29,219	7,158
Total Europe	186	91	3,131	1,487	3,317	1,578

Other International	—	—	571	195	571	195
Worldwide	14,856	3,500	21,395	7,793	36,251	11,293

In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future. If production is not established or we take no other action to extend the terms of the leases, licenses, or concessions, undeveloped acreage listed in the table below will expire over the next three years. We plan to continue the terms of many of these licenses and concession areas or retain leases through operational or administrative actions.

	Net Undeveloped Acres Expiring		
(In thousands)	2013	2014	2015
U.S.	436	189	130
Canada	—	—	—
Total North America	436	189	130
E.G.	—	36	—
Other Africa	858	—	189
Total Africa	858	36	189
Total Europe	—	216	1,155
Other International	—	—	49
Worldwide	1,294	441	1,523

Marketing and Midstream

Our E&P segment includes activities related to the marketing and transportation of substantially all of our liquid hydrocarbon and natural gas production. These activities include the transportation of production to market centers, the sale of commodities to third parties and storage of production. We balance our various sales, storage and transportation positions through what we call supply optimization, which can include the purchase of commodities from third parties for resale. Supply optimization serves to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points.

As discussed previously, we currently own and operate gathering systems and other midstream assets in some of our production areas. We are continually evaluating value-added investments in midstream infrastructure or in capacity in third-party systems.

Delivery Commitments

We have committed to deliver quantities of crude oil and natural gas to customers under a variety of contracts. As of December 31, 2012, those contracts for fixed and determinable amounts relate primarily to Eagle Ford liquid hydrocarbon production. A minimum of 54 mbbld is to be delivered at variable pricing through mid-2017 under two contracts. Our current production rates and proved reserves related to the Eagle Ford shale are sufficient to meet these commitments, but the contracts also provide for a monetary shortfall penalty or delivery of third-party volumes.

Oil Sands Mining Segment

We hold a 20 percent non-operated interest in the AOSP, an oil sands mining and upgrading joint venture located in Alberta, Canada. The joint venture produces bitumen from oil sands deposits in the Athabasca region utilizing mining techniques and upgrades the bitumen to synthetic crude oils and vacuum gas oil. The AOSP's mining and extraction assets are located near Fort McMurray, Alberta and include the Muskeg River and the Jackpine mines. Gross design capacity of the combined mines is 255,000 (51,000 net to our interest) barrels of bitumen per day. The AOSP base and expansion 1 Scotford upgrader is at Fort Saskatchewan, northeast of Edmonton, Alberta. As of December 31, 2012, we own or have rights to participate in developed and undeveloped leases totaling approximately 216,000 gross (43,000 net) acres. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta.

The five year AOSP Expansion 1 was completed in 2011. The Jackpine mine commenced production under a phased start-up in the third quarter of 2010 and began supplying oil sands ore to the base processing facility in the fourth quarter of 2010. The upgrader expansion was completed and commenced operations in the second quarter of 2011. Synthetic crude oil sales volumes for 2012 were 47 mbbld and net of royalty production was 41 mbbld. Phase one of debottlenecking opportunities was approved in 2011 and is expected to be completed in the second quarter of 2013. Future expansions and additional debottlenecking opportunities remain under review with no formal approvals expected until 2014.

Current AOSP operations use established processes to mine oil sands deposits from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Ore is mined using traditional truck and shovel mining techniques. The mined ore passes through primary crushers to reduce the ore chunks in size and is then sent to rotary breakers where the ore chunks are further reduced to smaller particles. The particles are combined with hot water to create slurry. The slurry moves through the extraction process where it separates into sand, clay and bitumen-rich froth. A solvent is added to the bitumen froth to separate out the remaining solids, water and heavy asphaltenes. The solvent washes the sand and produces clean bitumen that is required for the upgrader to run efficiently. The process yields a mixture of solvent and bitumen which is then transported from the mine to the Scotford upgrader via the approximately 300 mile Corridor Pipeline.

The bitumen is upgraded at Scotford using both hydrotreating and hydroconversion processes to remove sulfur and break the heavy bitumen molecules into lighter products. Blendstocks acquired from outside sources are utilized in the production of our saleable products. The upgrader produces synthetic crude oil and vacuum gas oil. The vacuum gas oil is sold to an affiliate of the operator under a long term contract at market-related prices, and the other products are sold in the marketplace.

In the fourth quarter of 2012, regulatory hearings were completed to consider the AOSP Jackpine mine expansion project. The regulatory application was submitted in 2007 and describes a potential oil sands mining development project of 100,000 gross bbld and includes additional mining areas, associated processing facilities utilities and infrastructure. A regulatory decision is expected to be published in the second quarter of 2013.

The governments of Alberta and Canada have agreed to partially fund Quest CCS for 865 million Canadian dollars. Financing has begun to be received over a period of 15 years, including development, construction and 10 years of operations. However, the funding is subject to conditions of achieving certain performance objectives. In the third quarter of 2012, the Energy and Resources Conservation Board ("ERCB"), Alberta's primary energy regulator, conditionally approved and the AOSP partners made a final investment decision on Quest CCS.

As announced in October 2012, we have engaged in discussions with respect to a potential sale of a portion of our 20 percent interest in the AOSP. Given the uncertainty of such a transaction, potential proceeds have not been included in our previously stated goal of divesting between $1.5 billion and $3 billion between 2011 and 2013.

The above discussion contains forward-looking statements with regard to discussions with respect to a potential sale of a portion of our 20 percent interest in the AOSP and the application for the Jackpine mine expansion. The potential sale of a portion of our interest in the AOSP is subject to successful negotiations and execution of definitive agreements. The Jackpine mine expansion could be affected by the inability to obtain or delay in obtaining necessary government and third-party approvals and permits. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Reserves

Estimated Reserve Quantities

The following table sets forth estimated quantities of our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves based upon an unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2012, 2011 and 2010. Included in our liquid hydrocarbon reserves, are NGLs which represent approximately 6 percent of our total proved reserves on an oil equivalent basis. Approximately 70 percent of those NGLs reserves are associated with our U.S. unconventional liquids-rich plays.

Reserves are disclosed by continent, by country, if the proved reserves related to any geographic area, on an oil-equivalent barrel basis represent 15 percent or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent, or a continent. Approximately 70 percent of our proved reserves are located in OECD countries.

	North America			Africa			Europe	
December 31, 2012	U.S.	Canada	Total	E.G.	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbons *(mmbbl)*	198	—	198	68	168	236	84	518
Natural gas *(bcf)*	546	—	546	980	99	1,079	28	1,653
Synthetic crude oil *(mmbbl)*	—	653	653	—	—	—	—	653
Total proved developed reserves *(mmboe)*	289	653	942	231	185	416	88	1,446
Proved Undeveloped Reserves								
Liquid hydrocarbons *(mmbbl)*	277	—	277	42	59	101	5	383
Natural gas *(bcf)*	497	—	497	444	110	554	75	1,126
Total proved undeveloped reserves *(mmboe)*	360	—	360	116	77	193	18	571
Total Proved Reserves								
Liquid hydrocarbons *(mmbbl)*	475	—	475	110	227	337	89	901
Natural gas *(bcf)*	1,043	—	1,043	1,424	209	1,633	103	2,779
Synthetic crude oil *(mmbbl)*	—	653	653	—	—	—	—	653
Total proved reserves *(mmboe)*	649	653	1,302	347	262	609	106	2,017

	North America			Africa			Europe	
December 31, 2011	U.S.	Canada	Total	E.G.	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbons *(mmbbl)*	141	—	141	78	179	257	84	482
Natural gas *(bcf)*	551	—	551	1,104	104	1,208	40	1,799
Synthetic crude oil *(mmbbl)*	—	623	623	—	—	—	—	623
Total proved developed reserves *(mmboe)*	233	623	856	262	196	458	91	1,405
Proved Undeveloped Reserves								
Liquid hydrocarbons *(mmbbl)*	138	—	138	39	61	100	13	251
Natural gas *(bcf)*	321	—	321	467	—	467	79	867
Total proved undeveloped reserves *(mmboe)*	191	—	191	117	61	178	26	395
Total Proved Reserves								
Liquid hydrocarbons *(mmbbl)*	279	—	279	117	240	357	97	733
Natural gas *(bcf)*	872	—	872	1,571	104	1,675	119	2,666
Synthetic crude oil *(mmbbl)*	—	623	623	—	—	—	—	623
Total proved reserves *(mmboe)*	424	623	1,047	379	257	636	117	1,800

	North America			Africa			Europe	
December 31, 2010	U.S.	Canada	Total	E.G.	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbons *(mmbbl)*	124	—	124	86	180	266	89	479
Natural gas *(bcf)*	591	—	591	1,186	104	1,290	43	1,924
Synthetic crude oil *(mmbbl)*	—	433	433	—	—	—	—	433
Total proved developed reserves *(mmboe)*	222	433	655	284	198	482	96	1,233
Proved Undeveloped Reserves								
Liquid hydrocarbons *(mmbbl)*	49	—	49	33	59	92	10	151
Natural gas *(bcf)*	154	—	154	465	1	466	73	693
Synthetic crude oil *(mmbbl)*	—	139	139	—	—	—	—	139
Total proved undeveloped reserves *(mmboe)*	75	139	214	110	59	169	22	405
Total Proved Reserves								
Liquid hydrocarbons *(mmbbl)*	173	—	173	119	239	358	99	630
Natural gas *(bcf)*	745	—	745	1,651	105	1,756	116	2,617
Synthetic crude oil *(mmbbl)*	—	572	572	—	—	—	—	572
Total proved reserves *(mmboe)*	297	572	869	394	257	651	118	1,638

The significant increase in proved reserves from 2011 to 2012 was primarily due to drilling programs within our shale plays and Eagle Ford acquisitions. Synthetic crude oil reserves also increased due to revised technical assessment and a change in royalty related to lower prices.

The above estimated quantities of proved liquid hydrocarbon and natural gas reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. The above estimated quantities of synthetic crude oil reserves are forward-looking statements and are based on presently known physical data, economic recoverability and operating conditions. To the extent these assumptions prove inaccurate, actual recoveries and development costs could be different than current estimates. For additional details of the estimated quantities of proved reserves at the end of each of the last three years, see Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities.

Preparation of Reserve Estimates

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Liquid hydrocarbon, natural gas and synthetic crude oil reserve estimates are reviewed and approved by our Corporate Reserves Group, which includes our Director of Corporate Reserves and her staff of Reserve Coordinators. Liquid hydrocarbon and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QRE"). QRE are engineers or geoscientists with a minimum of a Bachelor of Science degree in the appropriate technical field, have a minimum of three years of industry experience with at least one year in reserve estimation and have completed Marathon Oil's Qualified Reserve Estimator training course. Reserve Coordinators screen all fields with proved reserves of 20 mmboe or greater every year to determine if a field review will be performed. Any change to proved reserve estimates in excess of 2.5 mmboe on a total field basis, within a single month, must be approved by Corporate Reserves Group management. All other proved reserve changes must be approved by a Reserve Coordinator.

Our Director of Corporate Reserves, who reports to our Chief Financial Officer, has a Bachelor of Science degree in petroleum engineering and a Master of Business Administration. Her 38 years of experience in the industry include 27 with Marathon Oil. She is active in industry and professional groups, having served on the Society of Petroleum Engineers ("SPE") Oil and Gas Reserves Committee ("OGRC"), chairing in 2008 and 2009. As a member of the OGRC, she participated in the development of the Petroleum Resource Management System. She chaired the development of the OGRC comments on the SEC's proposed modernization of oil and gas reporting and was a member of the American Petroleum Institute's Ad Hoc group that provided comments on the same topic.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants of Calgary, Canada, third-party consultants. Their reports for all years are filed as exhibits to this Annual Report on Form 10-K. The team lead responsible for the estimates of our OSM reserves has 34 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 1986. He is a member of SPE, having served as regional director from 1998 through 2001. The second team member has 13 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 2009. Both are registered Practicing Professional Engineers in the Province of Alberta.

Audits of Estimates

Third-party consultants are engaged to provide independent estimates for fields that comprise 80 percent of our total proved reserves over a rolling four-year period for the purpose of auditing the in-house reserve estimates. We met this goal for the four-year period ended December 31, 2012. We established a tolerance level of 10 percent such that initial estimates by the third-party consultants are accepted if they are within 10 percent of our internal estimates. Should the third-party consultants' initial analysis fail to reach our tolerance level, both our team and the consultants re-examine the information provided, request additional data and refine their analysis if appropriate. This resolution process is continued until both estimates are within 10 percent. In the very limited instances where differences outside the 10 percent tolerance cannot be resolved by year end, a plan to resolve the difference is developed and our senior management is informed. This process did not result in significant changes to our reserve estimates in 2012 or 2011. There were no third-party audits performed in 2010.

During 2012, Netherland, Sewell & Associates, Inc. ("NSAI") prepared a Certification of December 31, 2011 reserves for the Alba field in E.G. The NSAI summary report is filed as an exhibit to this Annual Report on Form 10-K. Members of the NSAI team have many years of industry experience, having worked for large, international oil and gas companies before joining NSAI. The senior technical advisor has a Bachelor of Science degree in geophysics and over 15 years of experience in the estimation of and evaluation of reserves. The second member has a Bachelor of Science degree in chemical engineering and Master of Business Administration along with over 3 years of experience in estimation and evaluation of reserves. Both are licensed in the state of Texas.

Ryder Scott Company ("Ryder Scott") performed audits of several of our fields in 2012 and 2011. Their summary reports on audits performed in 2012 and 2011 are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 20 years of industry experience, having worked for a major international oil and gas company before joining Ryder Scott. He has a Bachelor of Science degree in mechanical engineering, is a member of SPE where he served on the Oil and Gas Reserves Committee and is a registered Professional Engineer in the state of Texas.

Changes in Proved Undeveloped Reserves

As of December 31, 2012, 571 mmboe of proved undeveloped reserves were reported, an increase of 176 mmboe from December 31, 2011. The following table shows changes in total proved undeveloped reserves for 2012:

(mmboe)	
Beginning of year	395
Revisions of previous estimates	(13)
Improved recovery	2
Purchases of reserves in place	56
Extensions, discoveries, and other additions	201
Transfer to Proved Developed	(70)
End of year	571

Significant additions to proved undeveloped reserves during 2012 include 56 mmboe due to acquisitions in the Eagle Ford shale. Development drilling added 124 mmboe in the Eagle Ford, 35 mmboe in the Bakken and 15 mmboe in the Oklahoma Resource Basins shale play. A gas sharing agreement signed with the Libyan government in 2012 added 19 mmboe. Additionally, 30 mmboe were transferred from proved undeveloped to proved developed reserves in the Eagle Ford and 14 mmboe in the Bakken shale plays due to producing wells. Costs incurred in 2012, 2011 and 2010 relating to the development of proved undeveloped reserves, were $1,995 million $1,107 million and $1,463 million.

A total of 27 mmboe was booked as a result of reliable technology. Technologies included statistical analysis of production performance, decline curve analysis, rate transient analysis, reservoir simulation and volumetric analysis. The statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved undeveloped locations establish the reasonable certainty criteria required for booking reserves.

Projects can remain in proved undeveloped reserves for extended periods in certain situations such as behind-pipe zones where reserves will not be accessed until the primary producing zone depletes, large development projects which take more than five years to complete, and the timing of when additional gas compression is needed. Of the 571 mmboe of proved undeveloped reserves at December 31, 2012, 25 percent of the volume is associated with projects that have been included in proved reserves for more than five years. The majority of this volume is related to a compression project in E.G. that was sanctioned by our Board of Directors in 2004. The timing of the installation of compression is being driven by the reservoir performance with this project intended to maintain maximum production levels. Performance of this field since the Board sanctioned the project has far exceeded expectations. Estimates of initial dry gas in place have increased by roughly 10 percent between 2004 and 2010. Production is now expected to experience a natural decline from facility-limited plateau production in 2014, or possibly 2015. During 2012, the project received the approval of the E.G. government, allowing design and planning work to progress towards implementation, with completion expected by mid-2016.

Proved undeveloped reserves for the North Gialo development, located in the Libyan Sahara desert, were booked for the first time as proved undeveloped reserves in 2010. This development, which is anticipated to take more than five years to be developed, is being executed by the operator and encompasses a continuous drilling program including the design, fabrication and installation of extensive liquid handling and gas recycling facilities. Anecdotal evidence from similar development projects in the region led to an expected project execution of more than five years from the time the reserves were initially booked. Interruptions associated with the civil unrest in 2011 have extended the project duration. There are no other significant undeveloped reserves expected to be developed more than five years after their original booking.

As of December 31, 2012, future development costs estimated to be required for the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves for the years 2013 through 2017 are projected to be $2,665 million, $2,726 million, $2,955 million, $2,132 million, and $425 million.

The timing of future projects and estimated future development costs relating to the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. To the extent these assumptions prove inaccurate, actual recoveries, timing and development costs could be different than current estimates.

Net Production Sold

	North America			Africa			Europe	
	U.S.	Canada	Total	E.G.	Other	Total	Total	Grand Total
Year Ended December 31, 2012								
Liquid hydrocarbons *(mbbld)*[a]	107	—	107	36	42	78	97	282
Natural gas *(mmcfd)*[b][c]	358	—	358	428	15	443	86	887
Synthetic crude oil *(mbbld)*	—	41	41	—	—	—	—	41
Total production sold *(mboed)*	167	41	208	108	44	152	111	471
Year Ended December 31, 2011								
Liquid hydrocarbons *(mbbld)*[a]	75	—	75	38	5	43	101	219
Natural gas *(mmcfd)*[b][c]	326	—	326	443	—	443	81	850
Synthetic crude oil *(mbbld)*	—	38	38	—	—	—	—	38
Total production sold *(mboed)*	129	38	167	112	5	117	115	399
Year Ended December 31, 2010								
Liquid hydrocarbons *(mbbld)*[a]	70	—	70	38	45	83	92	245
Natural gas *(mmcfd)*[b][c]	364	—	364	405	4	409	87	860
Synthetic crude oil *(mbbld)*	—	24	24	—	—	—	—	24
Total production sold *(mboed)*	131	24	155	106	45	151	106	412

[a] The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

[b] U.S. natural gas volumes exclude volumes produced in Alaska that are stored for later sale in response to seasonal demand, although our reserves have been reduced by those volumes.

[c] Excludes volumes acquired from third parties for injection and subsequent resale.

Average Sales Price per Unit

	North America			Africa			Europe	
(Dollars per unit)	U.S.	Canada	Total	E.G.	Other	Total	Total	Grand Total
Year Ended December 31, 2012								
Liquid hydrocarbons *(bbl)*	$ 85.80	$ —	$ 85.80	$ 64.33	$ 127.31	$ 98.52	$115.16	$ 99.46
Natural gas *(mcf)*	3.91	—	3.91	0.24	5.76	0.43	10.45	2.80
Synthetic crude oil *(bbl)*	—	81.72	81.72	—	—	—	—	81.72
Year Ended December 31, 2011								
Liquid hydrocarbons *(bbl)*	$ 92.55	$ —	$ 92.55	$ 67.70	$ 112.56	$ 73.21	$115.55	$ 99.37
Natural gas *(mcf)*	4.95	—	4.95	0.24	0.70	0.24	9.75	2.96
Synthetic crude oil *(bbl)*	—	91.65	91.65	—	—	—	—	91.65
Year Ended December 31, 2010								
Liquid hydrocarbons *(bbl)*	$ 72.30	$ —	$ 72.30	$ 50.57	$ 89.15	$ 71.71	$ 81.95	$ 75.73
Natural gas *(mcf)*	4.71	—	4.71	0.24	0.70	0.25	7.04	2.82
Synthetic crude oil *(bbl)*	—	71.06	71.06	—	—	—	—	71.06

Average Production Cost per Unit[(a)]

	North America			Africa			Europe	
(Dollars per boe)	U.S.	Canada[(b)]	Total	E.G.	Other[(c)]	Total	Total	Grand Total
Years ended December 31:								
2012	$ 16.05	$ 61.55	$ 25.04	$ 3.59	$ 4.66	$ 3.90	$ 9.08	$ 14.44
2011	16.42	60.04	26.13	2.87	17.16	3.53	8.24	14.36
2010	14.16	69.24	22.58	2.81	4.18	3.23	7.49	11.59

(a) Production, severance and property taxes are excluded from the production costs used in the calculation of this metric.

(b) Production costs in 2010 include costs associated with a major turnaround and $64 million for a water abatement accrual in 2011.

(c) Production operations ceased in Libya in February 2011, but fixed costs continued to be incurred. Production resumed in 2012.

Integrated Gas

Our IG operations include natural gas liquefaction operations and methanol production operations. Also included in the financial results of the IG segment are the costs associated with ongoing development of projects to link stranded natural gas resources with key demand areas.

We hold a 60 percent interest in EGHoldings, which is accounted for under the equity method of accounting. EGHoldings has a 3.7 mmta LNG production facility on Bioko Island in E.G. LNG from the production facility is sold under a 3.4 mmta, or 460 mmcfd, sales and purchase agreement ending in 2023. The purchaser under the agreement takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index, regardless of destination. This production facility allows us to monetize our natural gas reserves from the Alba field, as natural gas for the facility is purchased from the Alba field participants under a long-term natural gas supply agreement. Gross sales of LNG from this production facility totaled 3.8 mmt, 4.1 mmt and 3.7 mmt in 2012, 2011 and 2010. Operational availability for this LNG production facility was 95 percent including a planned turnaround, while unplanned downtime was minimal at 1.5 percent. The turnaround was completed four days ahead of schedule and 15 percent under budget. In 2012, we continued discussions with the government of E.G. and our partners regarding a potential second LNG production train on Bioko Island.

We own a 45 percent interest in AMPCO, which is accounted for under the equity method of accounting. AMPCO owns a methanol plant located on Bioko Island in E.G. Feedstock for the plant is supplied from our natural gas production from the Alba field. Gross sales of methanol from the plant totaled 1.06 mmt, 1.04 mmt and 0.85 mmt in 2012, 2011 and 2010. Operational availability for this plant was 91 percent in 2012. Production from the plant is used to supply customers in Europe and the U.S.

The above discussion of the IG segment contains forward-looking statements with respect to the possible expansion of the LNG production facility in E.G. Factors that could potentially affect the possible expansion of the LNG production facility include partner and government approvals, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient reclassification capacity. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Competition and Market Conditions

Strong competition exists in all sectors of the oil and gas industry and, in particular, in the exploration for and development of new reserves. We compete with major integrated and independent oil and gas companies, as well as national oil companies, for the acquisition of oil and natural gas leases and other properties. Based upon statistics compiled in the "2012 Global Upstream Performance Review" published by IHS Herold Inc., we rank tenth among U.S.-based petroleum companies on the basis of 2011 worldwide liquid hydrocarbon and natural gas production. See Item 1A. Risk Factors for discussion of specific areas in which we compete and related risks.

We also compete with other producers of synthetic and conventional crude oil for the sale of our synthetic crude oil to refineries primarily in North America. Additional synthetic crude oil projects are being contemplated by various competitors and, if undertaken and completed, these projects may result in a significant increase in the supply of synthetic crude oil to the market. Since not all refineries are able to process or refine synthetic crude oil in significant volumes, there can be no assurance that sufficient market demand will exist at all times to absorb our share of the synthetic crude oil production from the AOSP at economically viable prices.

Our operating results are affected by price changes in conventional and synthetic crude oil, natural gas and petroleum products, as well as changes in competitive conditions in the markets we serve. Generally, results from production and OSM operations benefit from higher crude oil prices. Market conditions in the oil and gas industry are cyclical and subject to global economic and political events and new and changing governmental regulations. See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Overview – Market Conditions for additional discussion of the impact of prices on our operations.

Environmental, Health and Safety Matters

The Health, Environmental, Safety and Corporate Responsibility Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental, health and safety matters. Our Corporate Health, Environment, Safety and Security organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Corporate Emergency Response Team which oversees our response to any major environmental or other emergency incident involving us or any of our properties.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment, health and safety. These laws and regulations include the Occupational Safety and Health Act ("OSHA") with respect to the protection of health and safety of employees, the Clean Air Act ("CAA") with respect to air emissions, the Federal Water Pollution Control Act (also known as the Clean Water Act ("CWA") with respect to water discharges, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") with respect to releases and remediation of hazardous substances, the Oil Pollution Act of 1990 ("OPA-90") with respect to oil pollution and response, the National Environmental Policy Act with respect to evaluation of environmental impacts, the Endangered Species Act with respect to the protection of endangered or threatened species, the Resource Conservation and Recovery Act ("RCRA") with respect to solid and hazardous waste treatment, storage and disposal and the U.S. Emergency Planning and Community Right-to-Know Act with respect to the dissemination of information relating to certain chemical inventories. In addition, many other states and countries in which where we operate have their own laws dealing with similar matters.

These laws and regulations could result in costs to remediate releases of regulated substances, including crude oil, into the environment, or costs to remediate sites to which we sent regulated substances for disposal. In some cases, these laws can impose liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others (such as prior owners or operators of our assets) or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. New laws have been enacted and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new rules can only be broadly appraised until their implementation becomes more defined. Based on regulatory trends, particularly with respect to the CAA and its implementing regulations, we have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation, see Item 3. Legal Proceedings and Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Management’s Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

Air

In August 2012, the U.S. EPA published final New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP") that amended existing NSPS and NESHAP standards for oil and gas facilities as well as created a new NSPS for oil and gas production, transmission and distribution facilities. These rules have been challenged, and negotiations with the U.S. EPA over proposed changes to the rules continue. Compliance with these new rules will result in an increase in the costs of control equipment and labor and require additional notification, monitoring, reporting and recordkeeping for some of our facilities. The U.S. EPA was also notified in December 2012 that seven northeastern states intend to sue the U.S. EPA for failure to include methane standards in these rules. If successfully challenged, the addition of methane standards could further increase our costs to comply with this rule.

In July 2011, the U.S. EPA finalized a Federal Implementation Plan under the CAA that includes New Source Review ("NSR") regulations which apply to air emissions sources on Tribal Lands. This rule became effective on August 30, 2011, and requires the registration and/or pre-construction permitting of most of our facilities on Tribal Lands in Wyoming, Oklahoma and North Dakota. Rather than issue pre-construction permits for our facilities on Tribal Lands in North Dakota, in August of 2012, the U.S. EPA finalized an Interim Final Rule under the CAA that requires certain control equipment, recordkeeping, monitoring, and reporting with respect to these facilities. Compliance with this new rule will result in an increase in the costs of control, equipment and labor and will require additional notification, monitoring, reporting and recordkeeping for our facilities on Tribal Lands in North Dakota.

Climate Change

In 2010, the U.S. EPA promulgated rules that require us to monitor and submit an annual report on our greenhouse gas emissions. Our first reports made pursuant to this rule were submitted in September 2012. Further, state, national and international requirements to reduce greenhouse emissions are being proposed and in some cases promulgated. These requirements apply or could apply in countries in which we operate. Potential legislation and regulations pertaining to climate change could also affect our operations. The cost to comply with these laws and regulations cannot be estimated at this time. For additional information, see Item 1A. Risk Factors. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

Hydraulic Fracturing

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Hydraulic fracturing has been regulated at the state level through permitting and compliance requirements. State level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. In addition, the U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process. In the first quarter of 2010, the U.S. EPA announced its intention to conduct a comprehensive research study on the potential effects that hydraulic fracturing may have on water quality and public health. The U.S. EPA has issued an interim report in late 2012, and expects to issue a final report in 2014.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal or state laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs, which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

Remediation

The AOSP operations use established processes to mine deposits of bitumen from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Tailings are waste products created from the oil sands extraction process which are placed in ponds. The AOSP is required to reclaim its tailing ponds as part of its ongoing reclamation work. The reclamation process uses developing technology and there is an inherent risk that the current process may not be as effective or perform as required in order to meet the approved closure and reclamation plan. The AOSP continues to develop its current reclamation technology and continues to investigate alternate tailings management technologies. In February 2009, the ERCB issued a directive which more clearly defines criteria for managing oil sands tailings. We believe that we are substantially in compliance with the directive at this time. We could incur additional costs if further new regulations are issued or if we fail to comply in a timely manner.

Concentrations of Credit Risk

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. For the year 2012, sales to Statoil and to Shell Oil and its affiliates each accounted for more than 10 percent of our annual revenues. For the years 2011 and 2010, transactions with MPC accounted for more than 10 percent of our annual revenues. The majority of those transactions occurred while MPC was a wholly-owned subsidiary. In addition, sales of crude oil and natural gas produced in Libya to the Libyan National Oil Company accounted for more than 10 percent of our 2010 annual revenues.

Trademarks, Patents and Licenses

We currently hold a number of U.S. and foreign patents and have various pending patent applications. Although in the aggregate our trademarks, patents and licenses are important to us, we do not regard any single trademark, patent, license or group of related trademarks, patents or licenses as critical or essential to our business as a whole.

Employees

We had 3,367 active, full-time employees as of December 31, 2012. We consider labor relations with our employees to be satisfactory. We have not had any work stoppages or strikes pertaining to our employees.

Executive Officers of the Registrant

The executive officers of Marathon Oil and their ages as of February 1, 2013, are as follows:

Clarence P. Cazalot, Jr.	62	Chairman, President and Chief Executive Officer
Janet F. Clark	58	Executive Vice President and Chief Financial Officer
Sylvia J. Kerrigan	47	Executive Vice President, General Counsel and Secretary
Annell R. Bay	57	Vice President, Global Exploration
Eileen M. Campbell	55	Vice President, Public Policy
Steven P. Guidry	54	Vice President, Business Development
T. Mitch Little	49	Vice President, International Production Operations
Lance W. Robertson	40	Vice President, Eagle Ford Production Operations
Michael K. Stewart	55	Vice President, Finance and Accounting, Controller and Treasurer
Howard J. Thill	53	Vice President, Investor Relations and Public Affairs
Gretchen H. Watkins	44	Vice President, North America Production Operations

With the exception of Ms. Bay, Mr. Robertson and Ms. Watkins, all of the executive officers have held responsible management or professional positions with Marathon Oil or its subsidiaries for more than the past five years.

- Mr. Cazalot was appointed chairman of the board of directors effective July 2011 and was appointed president and chief executive officer effective January 2002.
- Ms. Clark was appointed executive vice president effective January 2007. Ms. Clark joined Marathon Oil in January 2004 as senior vice president and chief financial officer.
- Ms. Kerrigan was appointed executive vice president, general counsel and secretary effective October 2012, and was appointed general counsel and secretary effective November 2009. Prior to these appointments, Ms. Kerrigan was assistant general counsel since January 2003.
- Ms. Bay was appointed vice president, global exploration effective July 2011. Ms. Bay joined Marathon Oil in June 2008 as senior vice president, exploration for Marathon Oil Company. Before joining Marathon Oil, Ms. Bay served as vice president, exploration at Shell Exploration and Production Company since 2004.
- Ms. Campbell was appointed vice president, public policy effective June 2010. Prior to this appointment, Ms. Campbell was vice president, human resources since October 2000.
- Mr. Guidry was appointed vice president, business development effective July 2011. Mr. Guidry previously served as regional vice president for our Libya operations from November 2008 to June 2011. Prior to the Libya assignment, Mr. Guidry was regional vice president for Marathon Oil North American Production Operations from August 2006 to November 2008.

- Mr. Little was appointed vice president, international production operations effective September 2012. Prior to this appointment, Mr. Little was resident manager for our Norway operations and served as general manager, worldwide drilling and completions. Mr. Little joined Marathon Oil in 1986 and has held a number of engineering and management positions of increasing responsibility.

- Mr. Robertson was appointed vice president, Eagle Ford production operations effective October 2012. Mr. Robertson joined Marathon Oil in October 2011 as regional vice president, South Texas/Eagle Ford. Between 2004 and 2011, Mr. Robertson held a number of senior engineering and operations management roles of increasing responsibility with Pioneer Natural Resources in the U.S. and Canada.
- Mr. Stewart was appointed vice president, finance and accounting, controller and treasurer effective December 2011. Mr. Stewart previously served as vice president, accounting and controller from May 2006 to December 2011 and as controller from July 2005 to April 2006.
- Mr. Thill was appointed vice president, investor relations and public affairs effective January 2008. Mr. Thill was previously director of investor relations from April 2003 to December 2007.
- Ms. Watkins was appointed vice president, North America production operations effective September 2012. Previously, Ms. Watkins served as vice president, international production operations effective July 2011 and regional vice president effective November 2008. Ms. Watkins joined Marathon Oil in July 2008, as general manager Upstream. Before joining Marathon Oil, Ms. Watkins held a number of international leadership positions at BP.

Available Information

General information about Marathon Oil, including the Corporate Governance Principles and Charters for the Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee, can be found at www.marathonoil.com. In addition, our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available at http://ir.marathonoil.com.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. These documents are also available in hard copy, free of charge, by contacting our Investor Relations office. Information contained on our website is not incorporated into this Annual Report on Form 10-K or other securities filings.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

A substantial, extended decline in liquid hydrocarbon or natural gas prices would reduce our operating results and cash flows and could adversely impact our future rate of growth and the carrying value of our assets.

Prices for liquid hydrocarbons and natural gas fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our liquid hydrocarbons and natural gas. Historically, the markets for liquid hydrocarbons and natural gas have been volatile and may continue to be volatile in the future. Many of the factors influencing prices of liquid hydrocarbons and natural gas are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for liquid hydrocarbons and natural gas;
- the cost of exploring for, developing and producing liquid hydrocarbons and natural gas;
- the ability of the members of OPEC to agree to and maintain production controls;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornadoes;
- the price and availability of alternative and competing forms of energy;

- the effect of conservation efforts;
- domestic and foreign governmental regulations and taxes; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of liquid hydrocarbons and natural gas are uncertain.

Lower liquid hydrocarbon and natural gas prices may cause us to reduce the amount of these commodities that we produce, which may reduce our revenues, operating income and cash flows. Significant reductions in liquid hydrocarbon and natural gas prices could require us to reduce our capital expenditures or impair the carrying value of our assets.

Our offshore operations involve special risks that could negatively impact us.

Offshore exploration and development operations present technological challenges and operating risks because of the marine environment. Activities in deepwater areas may pose incrementally greater risks because of water depths that limit intervention capability and the physical distance to oilfield service infrastructure and service providers. Environmental remediation and other costs resulting from spills or releases may result in substantial liabilities.

Estimates of liquid hydrocarbon, natural gas and synthetic crude oil reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our liquid hydrocarbon, natural gas and synthetic crude oil reserves.

The proved reserve information included in this Annual Report on Form 10-K has been derived from engineering estimates. Estimates of liquid hydrocarbon and natural gas reserves were prepared by our in-house teams of reservoir engineers and geoscience professionals and were reviewed and approved by our Corporate Reserves Group. The synthetic crude oil reserves estimates were prepared by GLJ Petroleum Consultants, a third-party consulting firm experienced in working with oil sands. Reserves were valued based on the unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2012, 2011 and 2010, as well as other conditions in existence at those dates. Any significant future price change will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of liquid hydrocarbons, natural gas and bitumen that cannot be directly measured. (Bitumen is mined and then upgraded into synthetic crude oil.) Estimates of economically producible reserves and of future net cash flows depend on a number of variable factors and assumptions, including:

- location, size and shape of the accumulation as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other comparable producing areas;
- volumes of bitumen in-place and various factors affecting the recoverability of bitumen and its conversion into synthetic crude oil such as historical upgrader performance;
- the assumed effects of regulation by governmental agencies;
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and repair costs; and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

The discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves reflected in this Annual Report on Form 10-K should not be considered as the market value of the reserves attributable to our properties. As required by SEC Rule 4-10 of Regulation S-X, the estimated discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are based on an unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2012, 2011 and 2010, and costs applicable at the date of the estimate, while actual future prices and costs may be materially higher or lower.

In addition, the 10 percent discount factor required by the applicable rules of the SEC to be used to calculate discounted future net revenues for reporting purposes is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the oil and natural gas industry in general.

If we are unsuccessful in acquiring or finding additional reserves, our future liquid hydrocarbon and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.

The rate of production from liquid hydrocarbon and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance or identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves will decline materially as liquid hydrocarbons and natural gas are produced. Accordingly, to the extent we are not successful in replacing the liquid hydrocarbons and natural gas we produce, our future revenues will decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce liquid hydrocarbons and natural gas in promising areas;
- drilling success;
- the ability to complete long lead-time, capital-intensive projects timely and on budget;
- the ability to find or acquire additional proved reserves at acceptable costs; and
- the ability to fund such activity.

Future exploration and drilling results are uncertain and involve substantial costs.

Drilling for liquid hydrocarbons and natural gas involves numerous risks, including the risk that we may not encounter commercially productive liquid hydrocarbon and natural gas reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts and surface cratering;
- lack of access to pipelines or other transportation methods; and
- shortages or delays in the availability of services or delivery of equipment.

If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- increased costs or operational delays resulting from shortages of water;

- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;

- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;

- market-related increases in a project's debt or equity financing costs; and

- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our ongoing capital projects.

We may incur substantial capital expenditures and operating costs as a result of compliance with, and changes in environmental health, safety and security laws and regulations, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Our businesses are subject to numerous laws, regulations and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment such as the venting or flaring of natural gas, waste management, pollution prevention, greenhouse gas emissions, the protection of endangered species as well as laws, regulations, and other requirements relating to public and employee safety and health and to facility security. We have incurred and may continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws, regulations, and other requirements. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our operating results will be adversely affected. The specific impact of these laws, regulations, and other requirements may vary depending on a number of factors, including the age and location of operating facilities and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site cleanups or curtail operations that could materially and adversely affect our business, financial condition, results of operations and cash flows. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws, regulations, and other requirements could result in civil penalties or criminal fines and other enforcement actions against us.

We believe it is likely that the scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations that could affect our operations. Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of review, discussion or implementation in countries where we operate, including the U.S., Canada, and Norway, and the European Union. Our operations result in these greenhouse gas emissions. Through 2012, domestic legislative and regulatory efforts included proposed federal legislation and state actions to develop statewide or regional programs, each of which could impose reductions in greenhouse gas emissions. Further, in December 2012 at the Doha Climate Change Conference, countries agreed to extend the Kyoto Protocol to 2020. However, the U.S. Senate has not ratified the Kyoto Protocol, nor is it clear whether the U.S. Senate plans to ratify this agreement in the future. If the U.S. does ratify the Kyoto Protocol in the future or sign a new international agreement, such actions could result in increased costs to operate and maintain our facilities, capital expenditures to install new emission controls at our facilities, and costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for liquid hydrocarbons and natural gas, and create delays in our obtaining air pollution permits for new or modified facilities.

Although there may be adverse financial impact (including compliance costs, potential permitting delays and potential reduced demand for liquid hydrocarbons or natural gas) associated with any legislation, regulation, or other action by the U.S. EPA, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the fact that requirements have only recently been adopted and the present uncertainty regarding any additional measures and how they will be implemented. Private party litigation has also been brought against some emitters of greenhouse gas emissions.

The potential adoption of federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. The U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process. Consideration of new federal regulation and increased state oversight continues to arise. The U.S. EPA announced in the first quarter of 2010 its intention to conduct a comprehensive research study on the potential effects that hydraulic fracturing may have on water quality and public health. The U.S. EPA has issued an interim report in late 2012, and expects to issue a final report in 2014. In addition, various state-level initiatives in regions with substantial shale gas resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of liquid hydrocarbons and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal or state laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

Worldwide political and economic developments and changes in law could adversely affect our operations and materially reduce our profitability and cash flows.

Local political and economic factors in global markets could have a material adverse effect on us. A total of 61 percent of our liquid hydrocarbon and natural gas sales volumes in 2012 was derived from production outside the U.S. and 52 percent of our proved liquid hydrocarbon and natural gas reserves as of December 31, 2012 were located outside the U.S. All of our synthetic crude oil production and proved reserves are located in Canada. We are, therefore, subject to the political, geographic and economic risks and possible terrorist activities attendant to doing business with suppliers located within or outside of the U.S. There are many risks associated with operations in countries and in global markets, such as E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq and Libya, including:

- changes in governmental policies relating to liquid hydrocarbon or natural gas and taxation;
- other political, economic or diplomatic developments and international monetary fluctuations;
- political and economic instability, war, acts of terrorism and civil disturbances;
- the possibility that a government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens; and
- fluctuating currency values, hard currency shortages and currency controls.

Since January 2010, there have been varying degrees of political instability and public protests, including demonstrations which have been marked by violence, within some countries in the Middle East including Bahrain, Egypt, Iraq, Libya, Syria, Tunisia and Yemen. Some political regimes in these countries are threatened or have changed as a result of such unrest.

If such unrest continues to spread, conflicts could result in civil wars, regional conflicts, and regime changes resulting in governments that are hostile to the U.S. These may have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates and reduced demand for our products;
- negative impact on the world crude oil supply if transportation avenues are disrupted;
- security concerns leading to the prolonged evacuation of our personnel;
- damage to, or the inability to access, production facilities or other operating assets; and
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations.

Continued hostilities in the Middle East and the occurrence or threat of future terrorist attacks could adversely affect the economies of the U.S. and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for liquid hydrocarbons and natural gas. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate.

Actions of governments through tax legislation and other changes in law, executive order and commercial restrictions could reduce our operating profitability, both in the U.S. and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future. Changes in law could also adversely affect our results, such as the adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information or that could cause us to violate the non-disclosure laws of other countries.

Our commodity price risk management and trading activities may prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty risk.

To the extent that we engage in price risk management activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Our business could be negatively impacted by cyber-attacks targeting our computer and telecommunications systems and infrastructure.

Computers and telecommunication devices are integrated into our business operations and are used as a part of our liquid hydrocarbon and natural gas production and distribution systems in the U.S. and abroad, including those systems which are utilized to transport our production to market. A cyber-attack impacting these computers and telecommunication devices, or the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets and make it difficult or impossible to accurately account for production and settle transactions. Although we utilize various procedures and controls to mitigate our exposure to such risk, cyber-attacks are evolving and unpredictable. These attacks could include, but are not limited to, malicious software, attempts to gain unauthorized access to data, other electronic security breaches that could lead to disruptions in critical systems, the unauthorized release of protected information and the corruption or loss of data. The occurrence of such an attack could lead to financial losses and have a negative impact on our results of operations.

Our operations may be adversely affected by pipeline and midstream capacity constraints.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities, railcars and tanker transportation. If any pipelines, railcars or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport our liquid hydrocarbons and natural gas, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

We typically seek the acquisition of crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to fully assess possible deficiencies and potential problems. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as previously discussed), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

We operate in a highly competitive industry, and many of our competitors are larger and have available resources in excess of our own.

The oil and gas industry is highly competitive, and many competitors, including major integrated and independent oil and gas companies, as well as national oil companies, are larger and have substantially greater resources at their disposal than we do. We compete with these companies for the acquisition of oil and natural gas leases and other properties. We also compete with these companies for equipment and personnel, including petroleum engineers, geologists, geophysicists and other specialists, required to develop and operate those properties and in the marketing of oil and natural gas to end-users. Such competition can significantly increase costs and affect the availability of resources, which could provide our larger competitors a competitive advantage when acquiring equipment, leases and other properties. They may also be able to use their greater resources to attract and retain experienced personnel.

Many of our major projects and operations are conducted with partners, which may decrease our ability to manage risk.

We often enter into arrangements to conduct certain business operations, such oil and gas exploration and production, oil sands mining or pipeline transportation, with partners in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. In addition, misconduct, fraud, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our partners could have a significant negative impact on our business and reputation.

Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.

Our E&P operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, hurricanes and other adverse weather, tsunamis, earthquakes, volcanic eruptions or nuclear or other disasters, labor disputes and accidents. Our OSM operations are subject to business interruptions due to breakdown or failure of equipment or processes and unplanned events such as fires, earthquakes, explosions or other interruptions. These same risks can be applied to the third-parties which transport crude oil from our facilities. A prolonged disruption in the ability of any pipeline or vessels to transport crude oil could contribute to a business interruption or increase costs.

Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage and resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, due to hurricane activity in recent years, the availability of insurance coverage for our offshore facilities for windstorms in the Gulf of Mexico region has been reduced or, in many instances, it is prohibitively expensive. As a result, our exposure to losses from future windstorm activity in the Gulf of Mexico region has increased.

Litigation by private plaintiffs or government officials could adversely affect our performance.

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, privacy laws, antitrust laws or any other laws or regulations that apply to our operations. In some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

In connection with our separation from MPC, MPC agreed to indemnify us for certain liabilities. However, there can be no assurance that the indemnity will be sufficient to protect us against the full amount of such liabilities, or that MPC's ability to satisfy its indemnification obligations will not be impaired in the future.

Pursuant to the Separation and Distribution Agreement and the tax sharing agreement we entered into with MPC in connection with the spin-off, MPC agreed to indemnify us for certain liabilities. However, third parties could seek to hold us responsible for any of the liabilities that MPC agreed to retain or assume, and there can be no assurance that the indemnification from MPC will be sufficient to protect us against the full amount of such liabilities, or that MPC will be able to fully satisfy its indemnification obligations. In addition, even if we ultimately succeed in recovering from MPC any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves.

The spin-off could result in substantial tax liability.

We obtained a private letter ruling from the IRS substantially to the effect that the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the spin-off satisfies certain requirements necessary to obtain tax-free treatment under Section 355 of the Code. Rather, the private letter ruling was based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the spin-off, we also obtained an opinion of outside counsel, substantially to the effect that, the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the Code. The opinion relied on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by MPC and us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion is not binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail.

If, notwithstanding receipt of the private letter ruling and opinion of counsel, the spin-off were determined not to qualify under Section 355 of the Code, each U.S. holder of our common stock who received shares of MPC common stock in the spin-off would generally be treated as receiving a taxable distribution of property in an amount equal to the fair market value of the shares of MPC common stock received. That distribution would be taxable to each such stockholder as a dividend to the extent of our accumulated earnings and profits as of the effective date of the spin-off. For each such stockholder, any amount that exceeded those earnings and profits would be treated first as a non-taxable return of capital to the extent of such stockholder's tax basis in its shares of our common stock with any remaining amount being taxed as a capital gain. We would be subject to tax as if we had sold all the outstanding shares of MPC common stock in a taxable sale for their fair market value and would recognize taxable gain in an amount equal to the excess of the fair market value of such shares over our tax basis in such shares.

Under the terms of the Tax Sharing Agreement we entered into with MPC in connection with the spin-off, MPC is generally responsible for any taxes imposed on MPC or us and our subsidiaries in the event that the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment as a result of actions taken, or breaches of representations and warranties made in the Tax Sharing Agreement, by MPC or any of its affiliates. However, if the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment because of actions or failures to act by us or any of our affiliates, we would be responsible for all such taxes.

We may issue preferred stock whose terms could dilute the voting power or reduce the value of Marathon Oil common stock.

Our restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over Marathon Oil common stock respecting dividends and distributions, as our Board of Directors generally may determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of Marathon Oil common stock. For example, we could grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we could assign to holders of preferred stock could affect the residual value of the common stock.

Item 1B.   Unresolved Staff Comments

None.

Item 2.   Properties

The location and general character of our principal liquid hydrocarbon and natural gas properties, oil sands mining properties and facilities, and other important physical properties have been described by segment under Item 1. Business.

Net liquid hydrocarbon, natural gas, and synthetic crude oil sales volumes are set forth in Item 8. Financial Statements and Supplementary Data – Supplemental Statistics. Estimated net proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are set forth in Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities – Estimated Quantities of Proved Oil and Gas Reserves. The basis for estimating these reserves is discussed in Item 1. Business – Reserves.

Item 3.   Legal Proceedings

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Litigation

In March 2011, Noble Drilling (U.S.) LLC ("Noble") filed a lawsuit against us in the District Court of Harris County, Texas alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. Noble is seeking an unspecified amount of damages. We are vigorously defending this litigation. The ultimate outcome of this lawsuit, including any financial effect on us, remains uncertain. We do not believe an estimate of a reasonably probable loss (or range of loss) can be made for this lawsuit at this time.

Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2012, under federal and state environmental laws. Except as described herein, it is not possible to predict accurately the ultimate outcome of these matters; however, management's belief set forth in the first paragraph under Legal Proceedings above takes such matters into account.

We have been working with the North Dakota Department of Health to resolve voluntary disclosures we made in 2009 relating to potential Clean Air Act violations relating to our operations on state lands in the Bakken shale. The amount of the potential fine is estimated to be $185,000.

As of December 31, 2012, we have sites across the country where remediation is being sought under environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information, which is in many cases preliminary and incomplete, we believe that total clean-up and remediation costs in connection with these sites will be less than $28 million, the majority of which have already been incurred.

The projected liability for clean-up and remediation provided in the preceding paragraph is a forward-looking statement. To the extent that our assumptions prove to be inaccurate, future expenditures may differ materially from those stated in the forward-looking statement.

Item 4.   Mine Safety Disclosures

Not applicable.

PART II

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

The principal market on which Marathon Oil common stock is traded is the New York Stock Exchange ("NYSE"). As of January 31, 2013, there were 43,354 registered holders of Marathon Oil common stock.

The following table reflects high and low sales prices for Marathon Oil common stock and the related dividend per share by quarter for the past two years:

	2012			2011*		
(Dollars per share)	High Price	Low Price	Dividends	High Price	Low Price	Dividends
Quarter 1	$35.06	$30.47	$0.17	$53.31	$37.34	$0.25
Quarter 2	$32.23	$23.32	$0.17	$54.17	$49.06	$0.25
Quarter 3	$31.09	$24.09	$0.17	$34.07	$21.58	$0.15
Quarter 4	$31.93	$29.30	$0.17	$29.34	$20.27	$0.15
Full Year	$35.06	$23.32	$0.68	$54.17	$20.27	$0.80

* On June 30, 2011, Marathon completed the spin-off of the downstream business. The June 30, 2011 closing price of our common stock on the NYSE was $52.68. On July 1, 2011, the opening price of our common stock on the NYSE was $32.95. Our quarterly dividend was also adjusted to $0.15 per share.

Dividends – Our Board of Directors intends to declare and pay dividends on Marathon Oil common stock based on the financial condition and results of operations of Marathon Oil Corporation, although it has no obligation under Delaware law or the Restated Certificate of Incorporation to do so. In determining the dividend policy with respect to Marathon Oil common stock, the Board will rely on the consolidated financial statements of Marathon Oil. Dividends on Marathon Oil common stock are limited to our legally available funds.

Issuer Purchases of Equity Securities – The following table provides information about purchases by Marathon Oil and its affiliated purchaser during the quarter ended December 31, 2012 of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934:

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased[a]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[c]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[c]
10/01/12 – 10/31/12	8,886	$29.92	—	$ 1,780,609,536
11/01/12 – 11/30/12	5,006	$30.22	—	$ 1,780,609,536
12/01/12 – 12/31/12	38,614 [b]	$30.50	—	$ 1,780,609,536
Total	52,506	$30.38	—	

[a] 22,200 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

[b] 30,306 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the "Dividend Reinvestment Plan") by the administrator of the Dividend Reinvestment Plan. Shares needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon Oil.

[c] We announced a share repurchase program in January 2006, and amended it several times in 2007 for a total authorized program of $5 billion. As of December 31, 2012, 78 million common shares had been acquired at a cost of $3,222 million, which includes transaction fees and commissions that are not reported in the table above. Of this total, 66 million shares had been acquired at a cost of $2,922 million prior to the spin-off of the downstream business.

Item 6. Selected Financial Data

(Dollars in millions, except per share data)	2012[(a)]	2011[(a)(b)]	2010[(a)(b)]	2009[(b)(c)]	2008[(b)(c)(d)]
Statement of Income Data[(b)]					
Revenues	$15,688	$ 14,663	$ 11,690	$ 8,524	$ 13,162
Income from continuing operations	1,582	1,707	1,882	716	2,192
Net income	1,582	2,946	2,568	1,463	3,528
Per Share Data					
Basic:					
Income from continuing operations	$2.24	$2.40	$2.65	$1.01	$3.09
Net income	$2.24	$4.15	$3.62	$2.06	$4.97
Diluted:					
Income from continuing operations	$2.23	$2.39	$2.65	$1.01	$3.08
Net income	$2.23	$4.13	$3.61	$2.06	$4.95
Statement of Cash Flows Data[(b)]					
Additions to property, plant and equipment related to continuing operations	$ 4,940	$ 3,295	$ 3,536	$ 3,349	$ 4,202
Dividends paid	480	567	704	679	681
Dividends per share	$0.68	$0.80	$0.99	$0.96	$0.96
Balance Sheet Data as of December 31:					
Total assets	$35,306	$ 31,371	$ 50,014	$ 47,052	$ 42,686
Total long-term debt, including capitalized leases	6,512	4,674	7,601	8,436	7,087

(a) Includes impairments, primarily related to E&P segment assets, of $371 million, $310 million and $447 million in 2012, 2011 and 2010, respectively (see Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements).

(b) Our downstream business was spun-off on June 30, 2011. Previous periods have been recast to reflect the business in discontinued operations (see Item 8. Financial Statements and Supplementary Data – Note 3 to the consolidated financial statements).

(c) Our businesses in Ireland and Gabon were sold in 2009. Previous periods have been recast to reflect these businesses in discontinued operations.

(d) Includes a $1,412 million impairment of goodwill related to the OSM reporting unit.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

We are an international energy company with operations in the U.S., Canada, Africa, the Middle East and Europe. Our operations are organized into three reportable segments:

- E&P which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- OSM which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.
- IG which produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Certain sections of Management’s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as "anticipates," "believes," "estimates," "expects," "targets," "plans," "projects," "could," "may," "should," "would" or similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in this Annual Report on Form 10-K.

Management’s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Item 1. Business, Item 1A. Risk Factors and Item 8. Financial Statements and Supplementary Data found in this Annual Report on Form 10-K.

Spin-off Downstream Business

On June 30, 2011, the spin-off of Marathon’s downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. Marathon stockholders at the close of business on the record date of June 27, 2011 received one share of MPC common stock for every two shares of Marathon common stock held. A private letter tax ruling received in June 2011 from the IRS affirmed the tax-free nature of the spin-off. Activities related to the downstream business have been treated as discontinued operations in 2011 and 2010 (see Item 8. Financial Statements and Supplementary Data – Note 3 to the consolidated financial statements for additional information).

Overview – Market Conditions

Exploration and Production

Prevailing prices for the various grades of crude oil and natural gas that we produce significantly impact our revenues and cash flows. The following table lists benchmark crude oil and natural gas price annual averages for the past three years.

Benchmark	2012	2011	2010
WTI crude oil *(Dollars per bbl)*	$94.15	$95.11	$79.61
Brent (Europe) crude oil *(Dollars per bbl)*	$111.65	$111.26	$79.51
Henry Hub natural gas *(Dollars per mmbtu)*[a]	$2.79	$4.04	$4.39

[a] Settlement date average.

Liquid hydrocarbon – Prices of crude oil have been volatile in recent years, but less so when comparing annual averages for 2012 and 2011. In 2011, crude prices increased over 2010 levels, with increases in Brent averages outstripping those in WTI.

The quality, location and composition of our liquid hydrocarbon production mix will cause our U.S. liquid hydrocarbon realizations to differ from the WTI benchmark. In 2012, 2011 and 2010, the percentage of our U.S. crude oil and condensate production that was sour averaged 37 percent, 58 percent and 68 percent. Sour crude contains more sulfur and tends to be heavier than light sweet crude oil so that refining it is more costly and produces lower value products; therefore, sour crude is considered of lower quality and typically sells at a discount to WTI. The percentage of our U.S. crude and condensate production that is sour has been decreasing as onshore production from the Eagle Ford and Bakken shale plays increases and production from the Gulf of Mexico declines. In recent years, crude oil sold along the U.S. Gulf Coast has been priced at a premium to WTI because the Louisiana Light Sweet benchmark has been tracking Brent, while production from inland areas farther from large refineries has been at a discount to WTI. NGLs were 10 percent, 7 percent and 6 percent of our U.S. liquid hydrocarbon sales in 2012, 2011 and 2010. In 2012, our sales of NGLs increased due to our development of U.S. unconventional liquids-rich plays.

Our international crude oil production is relatively sweet and is generally sold in relation to the Brent crude benchmark. The differential between WTI and Brent average prices widened significantly in 2011 and remained in 2012 in comparison to almost no differential in 2010.

Natural gas – A significant portion of our natural gas production in the lower 48 states of the U.S. is sold at bid-week prices or first-of-month indices relative to our specific producing areas. Average Henry Hub settlement prices for natural gas were lower in 2012 than in recent years. A decline in average settlement date Henry Hub natural gas prices began in September 2011 and continued into 2012. Although prices stabilized in late 2012, they have not increased appreciably.

Our other major natural gas-producing regions are E.G. and Europe. In the case of E.G,. our natural gas sales are subject to term contracts, making realizations less volatile. Because natural gas sales from E.G. are at fixed prices, our worldwide reported average natural gas realizations may not fully track market price movements. Natural gas prices in Europe have been significantly higher than in the U.S.

Oil Sands Mining

The OSM segment produces and sells various qualities of synthetic crude oil. Output mix can be impacted by operational problems or planned unit outages at the mines or upgrader. Sales prices for roughly two-thirds of the normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil marker, primarily WCS. In 2012, the WCS discount from WTI had increased, putting downward pressure on our average realizations.

The operating cost structure of the OSM operations is predominantly fixed and therefore many of the costs incurred in times of full operation continue during production downtime. Per-unit costs are sensitive to production rates. Key variable costs are natural gas and diesel fuel, which track commodity markets such as the Canadian Alberta Energy Company ("AECO") natural gas sales index and crude oil prices, respectively.

The table below shows average benchmark prices that impact both our revenues and variable costs.

Benchmark	2012	2011	2010
WTI crude oil *(Dollars per bbl)*	$94.15	$95.11	$79.61
WCS *(Dollars per bbl)*[(a)]	$73.18	$77.97	$65.31
AECO natural gas sales index *(Dollars per mmbtu)*[(b)]	$2.39	$3.68	$3.89

[(a)] Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.

[(b)] Monthly average day ahead index.

Integrated Gas

Our IG operations include production and marketing of products manufactured from natural gas, such as LNG and methanol, in E.G.

World LNG trade in 2012 has been estimated to be 240 mmt. Long-term, LNG continues to be in demand as markets seek the benefits of clean burning natural gas. Market prices for LNG are not reported or posted. In general, LNG delivered to the U.S. is tied to Henry Hub prices and will track with changes in U.S. natural gas prices, while LNG sold in Europe and Asia is indexed to crude oil prices and will track the movement of those prices. We have a 60 percent ownership in an LNG production facility in E.G., which sells LNG under a long-term contract at prices tied to Henry Hub natural gas prices. Gross sales from the plant were 3.8 mmt, 4.1 mmt and 3.7 mmt in 2012, 2011 and 2010.

We own a 45 percent interest in a methanol plant located in E.G. through our investment in AMPCO. Gross sales of methanol from the plant totaled 1.1 mmt, 1.0 mmt and 0.9 mmt in 2012, 2011 and 2010. Methanol demand has a direct impact on AMPCO’s earnings. Because global demand for methanol is rather limited, changes in the supply-demand balance can have a significant impact on sales prices. World demand for methanol in 2012 has been estimated to be 49 mmt. Our plant capacity of 1.1 mmt is about 2 percent of world demand.

Key Operating and Financial Activities

Significant operating and financial activities during 2012 include:

- Net proved reserve additions for the E&P and OSM segments combined of 389 mmboe, for a 226 percent reserve replacement ratio
- Increased proved liquid hydrocarbon and synthetic crude oil reserves by 316 mmbbls, for a reserve replacement of 268 percent for these commodities
- Recorded more than 95 percent average operational availability for operated E&P assets
- Increased E&P net sales volumes, excluding Libya, by 8 percent
- Eagle Ford shale average net sales volumes of 65 mboed for December 2012, a fourfold increase over December 2011
- Bakken shale average net sales volumes of 29 mboed, a 71 percent increase over last year
- Resumed sales from Libya and reached pre-conflict production levels
- International liquid hydrocarbon sales volumes, for which average realizations have exceeded WTI, were 62 percent of net E&P liquid hydrocarbon sales
- Closed $1 billion of acquisitions in the core of the Eagle Ford shale
- Assumed operatorship of the Vilje field located offshore Norway
- Signed agreements for new exploration positions in E.G., Gabon, Kenya and Ethiopia
- Issued $1 billion of 3-year senior notes at 0.9 percent interest and $1 billion of 10-year senior notes at 2.8 percent interest

Some significant 2013 activities through February 22, 2013 include:

- Closed sale of our Alaska assets in January 2013
- Closed sale of our interest in the Neptune gas plant in February 2013

Consolidated Results of Operations: 2012 compared to 2011

Consolidated income before income taxes was 38 percent higher in 2012 than consolidated income from continuing operations before income taxes were in 2011, largely due to higher liquid hydrocarbon sales volumes in our E&P segment, partially offset by lower earnings from our OSM and IG segments. The 7 percent decrease in income from continuing operations included lower earnings in the U.K. and E.G., partially offset by higher earnings in Libya. Also, in 2011 we were not in an excess foreign tax credit position for the entire year as we were in 2012. The effective income tax rate for continuing operations was 74 percent in 2012 compared to 61 percent in 2011.

Revenues are summarized in the following table:

(In millions)	2012	2011
E&P	$ 14,084	$ 13,029
OSM	1,552	1,588
IG	—	93
Segment revenues	15,636	14,710
Elimination of intersegment revenues	—	(47)
Unrealized gain on crude oil derivative instruments	52	—
Total revenues	$ 15,688	$ 14,663

E&P segment revenues increased $1,055 million from 2011 to 2012, primarily due to higher average liquid hydrocarbon sales volumes. E&P segment revenues included a net realized gain on crude oil derivative instruments of $15 million in 2012 while the impact of derivatives was not significant in 2011. See Item 8. Financial Statements and Supplementary Data – Note 16 to the consolidated financial statement for more information about our crude oil derivative instruments.

Included in our E&P segment are supply optimization activities which include the purchase of commodities from third parties for resale. See the Cost of revenues discussion as revenues from supply optimization approximate the related costs. Supply optimization serves to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Volumes associated with supply optimization have been decreasing in 2012 due to market dynamics and related commodity prices were also slightly lower in 2012.

Revenues from the sale of our U.S. production are higher in 2012 than in 2011 as a result of increased liquid hydrocarbon sales volumes from our U.S. shale plays. Lower liquid hydrocarbon and natural gas realizations partially offset the volume impact. The following table gives details of net sales and average realizations of our U.S. operations.

	2012	2011
U.S. Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*	107	75
Liquid hydrocarbon average realizations *(per bbl)*[(a)(b)]	$85.80	$92.55
Net crude oil and condensate sales *(mbbld)*	96	70
Crude oil and condensate *(per bbl)*	$91.29	$94.80
Net natural gas liquids sales *(mbbld)*	11	5
Natural gas liquids *(per bbl)*	$39.57	$58.53
Net natural gas sales *(mmcfd)*	358	326
Natural gas average realizations *(per mcf)*[(a)]	$3.91	$4.95

[(a)] Excludes gains or losses on derivative instruments.
[(b)] Inclusion of realized gains on crude oil derivative instruments would have increased average liquid hydrocarbon realizations $0.39 per bbl for 2012.

Revenues from our international operations are higher in 2012 than in 2011 primarily as a result of the previously discussed resumption of liquid hydrocarbon sales from Libya. Higher average liquid hydrocarbon realizations during 2012, again primarily related to Libyan crude oil, also contributed to the revenue increase. The following table gives details of net sales and average realizations of our international operations.

	2012	2011
International Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*[(a)]		
Europe	97	101
Africa	78	43
Total International	175	144
Liquid hydrocarbon average realizations *(per bbl)*[(b)]		
Europe	$115.16	$115.55
Africa	$98.52	$73.21
Total International	$107.78	$102.96
Net natural gas sales *(mmcfd)*		
Europe[(c)]	101	97
Africa	443	443
Total International	544	540
Natural gas average realizations *(per mcf)*[(b)]		
Europe	$10.47	$9.84
Africa[(d)]	$0.43	$0.24
Total International	$2.29	$1.97

[(a)] The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.
[(b)] Excludes gains or losses on derivative instruments.
[(c)] Includes natural gas acquired for injection and subsequent resale of 15 mmcfd and 16 mmcfd in 2012 and 2011.
[(d)] Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and EGHoldings, equity method investees. We include our share of Alba Plant LLC's income in our E&P segment and we include our share of AMPCO's and EGHoldings' income in our IG segment.

OSM segment revenues decreased $36 million from 2011 to 2012. The decrease was primarily the result of lower average realizations which were partially offset by the increase in sales volumes.

	2012	2011
OSM Operating Statistics		
Net synthetic crude oil sales *(mbbld)*[(a)]	47	43
Synthetic crude oil average realizations *(per bbl)*	$81.72	$91.65

(a) Includes bloodstocks.

IG segment revenues decreased to zero in 2012 from $93 million in 2011. Sales of LNG from our Alaska operations ceased in the third quarter of 2011 when we sold our interest in this production facility.

Income from equity method investments decreased $92 million from 2011 to 2012 primarily due to lower natural gas prices and turnarounds early in 2012 at our facilities in E.G. Also, in January 2012, we sold our equity investments in several Gulf of Mexico crude oil pipelines.

Net gain on disposal of assets in 2012 consists primarily of the $166 million gain on the sale of our interests in several Gulf of Mexico crude oil pipeline systems, reduced by the $36 million loss on the assignment of our Bone Bay and Kumawa exploration licenses in Indonesia and the $18 million loss on the sale of non-core Eagle Ford acreage. In 2011, net gain on disposal of assets is primarily related to sales of non-core assets, such as the Burns Point gas plant and the Alaska LNG facility, and the assignment of interests in our DJ Basin acreage position. See Item 8. Financial Statements and Supplementary Data – Note 6 to the consolidated financial statements for information about these dispositions.

Cost of revenues decreased $1,006 million from 2011 to 2012 primarily related to our supply optimization activities. Comparatively, costs related to supply optimization were lower by $1,152 million for 2012, primarily due to lower volumes in 2012 due to market dynamics. The related commodity prices were also slightly lower in 2012. Excluding the impact of supply optimization activities, E&P segment operating expenses have increased in proportion to our increased production from U.S. shale plays. Additionally, IG segment costs are lower in 2012 due to the sale of our interest in the Alaska LNG facility in the third quarter of 2011.

Depreciation, depletion and amortization increased $212 million from 2011 to 2012. Since both our E&P and OSM segments apply the units-of-production method to the majority of their assets, the previously discussed increases in sales volumes generally result in similar changes in DD&A. Increased DD&A in 2012 primarily reflects the impact of higher sales volumes. There was no depletion of our Alaska assets for much of 2012 because they were held for sale, which partially offset the DD&A increase. The DD&A rate (expense per barrel of oil equivalent), which is impacted by changes in proved reserves and capitalized costs, can also cause changes in our DD&A. Our E&P segment's DD&A rates have decreased slightly since 2011 primarily due to proved reserve additions. The following table provides DD&A rates for our E&P and OSM segments.

($ per boe)	2012	2011
DD&A rate		
E&P Segment		
United States	$ 24	$ 25
International	8	10
OSM Segment	$ 13	$ 13

Impairments in 2012 related primarily to our Ozona development in the Gulf of Mexico and to our Powder River Basin asset in Wyoming. Impairments in 2011 related primarily to our Droshky development in the Gulf of Mexico and an intangible asset for an LNG delivery contract at Elba Island. See Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements for further information about the impairments.

Other taxes increased $59 million from 2011 to 2012. With the increase in revenues related to higher sales volumes, production taxes increased. In addition, ad valorem taxes are higher because the value of our U.S. assets has increased with the recent acquisitions in the Eagle Ford shale.

Exploration expenses were higher in 2012 than 2011 primarily due to larger unproved property impairments. Unproved property impairments in 2012 related to the Marcellus shale, the Eagle Ford shale and Indonesia. The following table summarizes the components of exploration expenses.

(In millions)	2012	2011
Unproved property impairments	$ 227	$ 79
Dry well costs	230	278
Geological, geophysical, seismic	128	120
Other	144	167
Total exploration expenses	$ 729	$ 644

Net interest and other increased $112 million from 2011 to 2012 primarily as a result of less interest expense capitalized. See Item 8. Financial Statements and Supplementary Data – Note 9 to the consolidated financial statements for more information on net interest and other.

Loss on early extinguishment of debt in 2011 relates to debt retirements in February and March of 2011. See Item 8. Financial Statements and Supplementary Data – Note 17 to the consolidated financial statements for additional discussion of these transactions.

Provision for income taxes increased $1,811 million from 2011 to 2012 primarily due to the increase in pretax income, including the impact of the previously discussed resumption of sales in Libya in the first quarter of 2012. The following is an analysis of the effective income tax rates for 2012 and 2011:

	2012	2011
Statutory rate applied to income from continuing operations before income taxes	35%	35%
Effects of foreign operations, including foreign tax credits	18	6
Change in permanent reinvestment assertion	—	5
Adjustments to valuation allowances	21	14
Tax law changes	—	1
Effective income tax rate on continuing operations	74%	61%

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in "Corporate and other unallocated items" shown in the reconciliation of segment income to net income below.

Effects of foreign operations – The effects of foreign operations on our effective tax rate increased in 2012 as compared to 2011, primarily due to the resumption of sales of Libyan production in first quarter of 2012, where the statutory tax rate is in excess of 90 percent.

Change in permanent reinvestment assertion – In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognizing deferred U.S. tax on previously undistributed earnings.

Adjustments to valuation allowances – In 2012 and 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in those years.

See Item 8. Financial Statements and Supplementary Data – Note 10 to the consolidated financial statements for further information about income taxes.

Discontinued operations in 2011 reflect the June 30, 2011 spin-off of our downstream business and its historical operating results, net of tax. See Item 8. Financial Statements and Supplementary Data – Note 3 to the consolidated financial statements.

Segment Results: 2012 compared to 2011

Segment income for 2012 and 2011 is summarized and reconciled to net income in the following table.

(In millions)	2012	2011
E&P		
United States	$ 393	$ 366
International	1,488	1,791
E&P segment	1,881	2,157
OSM	176	256
IG	91	178
Segment income	2,148	2,591
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(441)	(317)
Impairments	(231)	(195)
Gain on dispositions	72	45
Unrealized gain on crude oil derivative instruments	34	—
Loss on early extinguishment of debt	—	(176)
Tax effect of subsidiary restructuring	—	(122)
Deferred income tax items	—	(61)
Water abatement - Oil Sands	—	(48)
Eagle Ford transaction costs	—	(10)
Income from continuing operations	1,582	1,707
Discontinued operations	—	1,239
Net income	$ 1,582	$ 2,946

U.S. E&P income increased $27 million from 2011 to 2012. The income increase was primarily the result of higher liquid hydrocarbon sales volumes as previously discussed, partially offset by lower liquid hydrocarbon and natural gas realizations and the impact of increased production operations on DD&A and operating expenses. In addition, exploration expenses were higher primarily due to dry wells and unproved property impairments.

International E&P income decreased $303 million from 2011 to 2012. The decrease included lower earnings in the U.K. and E.G. partially offset by higher earnings in Libya. Also, in 2011 we were not in an excess foreign tax credit position for the entire year as we were in 2012.

OSM segment income decreased $80 million from 2011 to 2012. As previously discussed, lower synthetic crude oil price realizations were the primary reason for the decrease in income partially offset by higher sales volumes.

IG segment income decreased $87 million from 2011 to 2012 primarily due to lower natural gas prices and turnarounds early in 2012 at our facilities in E.G. In addition, LNG sales volumes are lower in 2012 because we sold our interest in the Alaska LNG facility in the third quarter of 2011.

Consolidated Results of Operations: 2011 compared to 2010

Due to the spin-off of our downstream business on June 30, 2011, which is reported as discontinued operations, income from continuing operations is more representative of Marathon Oil as an independent energy company. Consolidated income from continuing operations before income taxes was 9 percent higher in 2011 than in 2010, largely due to higher liquid hydrocarbon prices. This improvement was more than offset by increased income taxes primarily the result of excess foreign tax credits generated during 2011 that we do not expect to utilize in the future. The effective income tax rate for continuing operations was 61 percent in 2011 compared to 54 percent in 2010.

Revenues are summarized in the following table:

(In millions)	2011	2010
E&P	$ 13,029	$ 10,782
OSM	1,588	833
IG	93	150
Segment revenues	14,710	11,765
Elimination of intersegment revenues	(47)	(75)
Total revenues	$ 14,663	$ 11,690

E&P segment revenues increased $2,247 million from 2010 to 2011, primarily due to higher average liquid hydrocarbon realizations, which were $99.37 per bbl in 2011, a 31 percent increase over 2010. Revenues in 2010 included net pre-tax gains of $95 million on derivative instruments intended to mitigate price risk on future sales of liquid hydrocarbons and natural gas.

Included in our E&P segment are supply optimization activities which include the purchase of commodities from third parties for resale. Supply optimization serves to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points. See the Cost of revenues discussion as revenues from supply optimization approximate the related costs. Higher average crude oil prices in 2011 compared to 2010 increased revenues related to supply optimization.

Revenues from the sale of our U.S. production were higher in 2011 primarily as a result of higher liquid hydrocarbon and natural gas price realizations, but sales volumes declined.

The following table gives details of net sales and average realizations of our U.S. operations.

	2011	2010
U.S. Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*	75	70
Liquid hydrocarbon average realizations *(per bbl)*[(a)]	$ 92.55	$ 72.30
Net crude oil and condensate sales *(mbbld)*	70	66
Crude oil and condensate *(per bbl)*	$ 94.80	$ 73.66
Net natural gas liquids sales *(mbbld)*	5	4
Natural gas liquids *(per bbl)*	$ 58.53	$ 50.71
Net natural gas sales *(mmcfd)*	326	364
Natural gas average realizations *(per mcf)*[(a)]	$ 4.95	$ 4.71

[(a)] Excludes gains or losses on derivative instruments.

Increased liquid hydrocarbon sales volumes in 2011 were a result of new wells in the Bakken shale, new production from acreage acquired in the Eagle Ford shale and increased production from the Droshky development in the Gulf of Mexico, which commenced operations in July 2010. Natural gas sales volumes were lower in 2011 as compared to 2010 due to the sale of a portion of our Powder River Basin asset in 2010, decreased demand in Alaska and natural field declines, partly offset by increased natural gas production from the Droshky development.

The following table gives details of net sales and average realizations of our international operations.

	2011	2010
International Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*[(a)]		
Europe	101	92
Africa	43	83
Total International	144	175
Liquid hydrocarbon average realizations *(per bbl)*[(b)]		
Europe	$115.55	$81.95
Africa	$73.21	$71.71
Total International	$102.96	$77.11
Net natural gas sales *(mmcfd)*		
Europe[(c)]	97	105
Africa	443	409
Total International	540	514
Natural gas average realizations *(per mcf)*[(b)]		
Europe	$9.84	$7.10
Africa[(d)]	$0.24	$0.25
Total International	$1.97	$1.65

(a) The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Excludes gains or losses on derivative instruments.

(c) Includes natural gas acquired for injection and subsequent resale of 16 mmcfd and 18 mmcfd in 2011 and 2010.

(d) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and EGHoldings, equity method investees. We include our share of Alba Plant LLC's income in our E&P segment and we include our share of AMPCO's and EGHoldings' income in our IG segment.

Compared to 2010, international liquid hydrocarbon sales volumes are lower due to the temporary cessation of production from Libya in February 2011. In the fourth quarter of 2011, limited production resumed from the Waha concessions, but we made no deliveries of hydrocarbons. Sales resumed in February 2012. Partially offsetting the impact of Libya, were higher liquid hydrocarbon sales from Norway due to increasing capacity of the Alvheim FPSO and from two new West Brae wells in the U.K. Natural gas sales volumes from E.G. were higher in 2011 due to a turnaround in 2010, while natural gas sales volumes from Europe were down primarily related to 2011 planned turnarounds and normal production declines in the U.K.

OSM segment revenues increased $755 million from 2010 to 2011. Revenues were impacted by net pre-tax gains of $25 million on derivative instruments in 2010. The increase in revenue is due to higher synthetic crude oil sales volumes and realizations as shown on the table below.

	2011	2010
OSM Operating Statistics		
Net synthetic crude oil sales *(mbbld)*[(a)]	43	29
Synthetic crude oil average realizations *(per bbl)*	$91.65	$71.06

(a) Includes blendstocks.

The 2011 sales volumes improved as a result of the Jackpine mine, which commenced operations in late 2010, and the upgrader expansion which was completed and commenced operations in the second quarter of 2011. Sales volumes in 2010 were impacted by a turnaround that commenced in late March 2010 that caused production to be completely shut down in April, with a staged resumption in May 2010.

IG segment revenues decreased $57 million in 2011 from 2010 because sales of LNG from our Alaska operations declined throughout 2011 as we planned to shut down the LNG facility. In the third quarter of 2011, sales from the LNG facility ceased completely because we sold our equity interest in the facility.

Income from equity method investments increased $118 million in 2011 from 2010 primarily due to the impact of higher liquid hydrocarbon prices on the earnings of certain of our equity method investees in 2011.

Net gain on disposal of assets in 2011 is primarily related to sales of non-core assets, such as the Burns Point gas plant and the Alaska LNG facility, and the assignment of interests in our DJ Basin acreage position. The 2010 gain is primarily related to the pretax gain of $811 million on the sale of a 20 percent non-operated interest in our Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. See Item 8. Financial Statements and Supplementary Data – Note 6 to the consolidated financial statements for discussion of significant dispositions.

Cost of revenues increased $1,439 million from 2010 to 2011 primarily due to the impact of higher crude oil prices on our supply optimization activities. Costs related to supply optimization were $3,599 million in 2011 compared to $2,530 million in 2010.

Additionally, total OSM segment costs increased for 2011 primarily because the Jackpine mine commenced production in late 2010 and the upgrader expansion came online in 2011. Although gross costs were up due to the increased volumes from the expansion, per barrel costs were declining in comparison with 2010. OSM segment costs also increased in 2011 when compared to 2010 due to the expansion's operation start-up costs. These increases were partially offset by no turnaround costs in 2011. We incurred $99 million in 2010 associated with the turnaround. Additionally, estimated net costs of $64 million were recorded in 2011 to address water flow in a previously mined and contained area of the Muskeg River mine.

Purchases from related parties increased $78 million from 2010 as a result of purchases from the Alba LPG plant in E.G., in which we own an equity interest. Higher liquid hydrocarbon prices in 2011 increased the value of those purchases.

Depreciation, depletion and amortization increased $210 million in 2011 from 2010. Since both our E&P and OSM segments apply the units-of-production method to the majority of their assets, the previously discussed increases or decreases in sales volumes generally result in similar changes in DD&A. Increased DD&A expense in 2011 reflects the impact of higher OSM segment sales volumes, partially offset by decreases in E&P segment sales volumes. The DD&A rate (expense per barrel of oil equivalent), which is impacted by changes in proved reserves and capitalized costs, can also cause changes in our DD&A. The DD&A rate for the OSM segment increased in 2011 when depreciation began on the upgrader expansion. The following table provides DD&A rates for our E&P and OSM segments.

($ per boe)	2011	2010
DD&A rate		
E&P Segment		
United States	$ 25	$ 22
International	10	9
OSM Segment	$ 13	$ 10

Impairments in 2011 related primarily to our Droshky development in the Gulf of Mexico for $273 million and an intangible asset for an LNG delivery contract at Elba Island. Impairments in 2010 include $423 million related to our Powder River Basin field in the first quarter, as well as smaller impairments to other E&P segment fields due to reductions in estimated reserves, reduced drilling expectations and declining natural gas prices. See Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements for further information about the impairments.

General and administrative expenses increased $53 million in 2011 compared to 2010 primarily due to additional compensation expense related to performance units and stock based compensation expense.

Other taxes increased $31 million in 2011 compared to 2010. With the increase in revenues, particularly related to higher prices, production and ad valorem taxes increased.

Exploration expenses were higher in 2011 than 2010 primarily due to higher dry well costs. Dry wells primarily related to Indonesia, the Gulf of Mexico, Norway and various U.S. onshore properties in both 2011 and 2010. In addition, costs related to some suspended exploratory wells in E.G. were expensed in 2010. Geologic and seismic costs have increased in 2011 over 2010 primarily related to the U.S. shale plays, Poland and the Kurdistan Region of Iraq.

The following table summarizes components of exploration expenses:

(In millions)	2011	2010
Unproved property impairments	$ 79	$ 46
Dry well costs	278	179
Geological, geophysical, seismic	120	116
Other	167	159
Total exploration expenses	$ 644	$ 500

Loss on early extinguishment of debt relates to debt retirements in February and March of 2011 and in April of 2010. See Item 8. Financial Statements and Supplementary Data – Note 17 to the consolidated financial statements for additional discussion of the 2011 transactions.

Provision for income taxes increased $545 million from 2010 to 2011 in part due to the increase in pretax income. In 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in 2011. A higher price and production outlook over the next several years for Norway due to better than expected performance contributed to generating these excess foreign tax credits. The following is an analysis of the effective income tax rates for 2011 and 2010:

	2011	2010
Statutory rate applied to income from continuing operations before income taxes	35%	35%
Effects of foreign operations, including foreign tax credits	6	20
Change in permanent reinvestment assertion	5	—
Adjustments to valuation allowances	14	(2)
Tax law changes	1	1
Effective income tax rate on continuing operations	61%	54%

The effective tax rate is influenced by a variety of factors including the geographical and functional sources of income, the relative magnitude of these sources of income, foreign currency remeasurement effects, and tax legislation changes. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in "Corporate and other unallocated items" shown in the reconciliation of segment income to net income shown below.

Effects of foreign operations – The effects of foreign operations on our effective tax rate decreased in 2011 as compared to 2010, primarily due to the suspension of all production operations in Libya in the first quarter of 2011, where the statutory tax rate is in excess of 90 percent.

Change in permanent reinvestment assertion – In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognized deferred U.S. tax on previously undistributed earnings.

Adjustments to valuation allowance – In 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in 2011.

See Item 8. Financial Statements and Supplementary Data – Note 10 to the consolidated financial statements for further information about income taxes.

Discontinued operations reflect the June 30, 2011 spin-off of our downstream business and the historical results of those operations, net of tax, for 2011 and 2010. See Item 8. Financial Statements and Supplementary Data – Note 3 to the consolidated financial statements.

Segment Results: 2011 compared to 2010

Segment income for 2011 and 2010 is summarized and reconciled to net income in the following table.

(In millions)	2011	2010
E&P		
United States	$ 366	$ 251
International	1,791	1,690
E&P segment	2,157	1,941
OSM	256	(50)
IG	178	142
Segment income	2,591	2,033
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(317)	(170)
Impairments	(195)	(286)
Gain on dispositions	45	407
Loss on early extinguishment of debt	(176)	(57)
Tax effect of subsidiary restructuring	(122)	—
Deferred income tax items	(61)	(45)
Water abatement – Oil Sands	(48)	—
Eagle Ford transaction costs	(10)	—
Income from continuing operations	1,707	1,882
Discontinued operations	1,239	686
Net income	$ 2,946	$ 2,568

U.S. E&P income increased $115 million from 2010 to 2011. The majority of the income increase was due to higher liquid hydrocarbon realizations in 2011, along with higher liquid hydrocarbon sales volumes, partially offset by higher DD&A in the Gulf of Mexico and increased exploration and operating costs.

International E&P income increased $101 million from 2010 to 2011. This increase was primarily related to higher liquid hydrocarbon realizations, partially offset by lower liquid hydrocarbon sales volumes and higher income taxes.

OSM segment income increased $306 million from 2010 to 2011. The increase in segment income was primarily the result of higher synthetic crude oil sales volumes and higher price realizations.

IG segment income increased $36 million from 2010 to 2011. The increase in income was primarily the result of higher LNG and methanol sales volumes, somewhat offset by lower Henry Hub gas prices.

Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Cash Flows

Net cash provided by continuing operations was $4,017 million in 2012 compared to $5,434 million in 2011 and $4,194 million in 2010. The $1,417 million decrease in 2012 was primarily the result of working capital changes related to the 2012 ramp-up of operations in the Eagle Ford shale and Libya along with the timing of tax payments. The $1,240 million increase in 2011 primarily reflects increased average realized prices.

Net cash used in investing activities totaled $5,439 million in 2012 compared to net cash used in investing activities related to continuing operations of $7,174 million in 2011 and $2,157 million in 2010. Significant investing activities include acquisitions, additions to property, plant and equipment and asset disposals.

Acquisitions in 2012 and 2011 included proved and unproved assets in the Eagle Ford shale play in south Texas. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for further information about the transactions.

In recent years, acquisitions and capital spending in the U.S. has been increasing, related to unconventional resource plays like the Eagle Ford shale and to Gulf of Mexico exploration when drilling was once again permitted. Historically, long-term projects, which cross several years, have been the reasons for our additions to property, plant and equipment. In our E&P segment, exploration and development projects in Angola impacted all three years. Development of fields tied back to the Alvheim FPSO occurred in 2010. In the OSM segment, the AOSP Expansion 1, which began in 2008, was substantially complete in 2010.

Disposal of assets totaled $467 million, $518 million, and $1,368 million in 2012, 2011 and 2010. In 2012, net proceeds resulted primarily from the sales of our interests in several Gulf of Mexico crude oil pipeline systems, a sell-down of our interest in the Harir and Safen blocks in the Kurdistan Region of Iraq, and the final collection of proceeds on a 2009 asset sale. Several sales of non-core assets in 2011 and acreage sell-downs resulted in net proceeds of $518 million. In 2010, we closed the sale of our 20 percent non-operated undivided interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola for $1.3 billion. See Item 8. Financial Statements and Supplementary Data – Note 6 to the consolidated financial statements for more information about dispositions.

Financing activities related to continuing operations provided cash of $1,600 million in 2012, but used cash of $5,211 million in 2011 and $1,343 million in 2010. Sources of cash in 2012 included the issuance of a net $200 million in commercial paper and $2 billion in senior notes. In connection with the spin-off, we distributed $1,622 million to MPC in the second quarter of 2011. Debt repayments of $145 million, $2,877 million, and $653 million occurred in 2012, 2011 and 2010. Purchases of common stock used $300 million in cash during 2011. Dividend payments were uses of cash in every year.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, the issuance of notes, our committed revolving credit facility and sales of non-strategic assets. Our working capital requirements are supported by these sources and we may issue commercial paper backed by our $2.5 billion revolving credit facility to meet short-term cash requirements. We issued $13.9 billion and repaid $13.7 billion of commercial paper in 2012, leaving a balance of $200 million outstanding at December 31, 2012. Because of the alternatives available to us as discussed above and our access to capital markets, we believe that our short-term and long-term liquidity is adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, defined benefit plan contributions, repayment of debt maturities, share repurchase program and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

Credit Arrangements and Borrowings

At December 31, 2012, we had $6,696 million in long-term debt outstanding, $184 million of which is due within one year. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

At December 31, 2012, we had no borrowings against our revolving credit facility and had $200 million in commercial paper outstanding under our commercial paper program, which is backed by the revolving credit facility. See Item 8. Financial Statements and Supplementary Data – Note 17 to the consolidated financial statements for a description of the revolving credit facility.

Shelf Registration

We have a universal shelf registration statement filed with the SEC, under which we, as a "well-known seasoned issuer" for purpose of SEC rules, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities from time to time.

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 25 percent and 20 percent at December 31, 2012 and 2011.

(Dollars in millions)	2012	2011
Commercial paper	$ 200	$ —
Long-term debt due within one year	184	141
Long-term debt	6,512	4,674
Total debt	$ 6,896	$ 4,815
Cash	$ 684	$ 493
Equity	$ 18,283	$ 17,159
Calculation:		
Total debt	$ 6,896	$ 4,815
Minus cash	684	493
Total debt minus cash	6,212	4,322
Total debt	6,896	4,815
Plus equity	18,283	17,159
Minus cash	684	493
Total debt plus equity minus cash	$ 24,495	$ 21,481
Cash-adjusted debt-to-capital ratio	25%	20%

Capital Requirements

Capital Spending

Our approved capital, investment and exploration budget for 2013 is $5,183 million. Additional details related to the 2013 budget are discussed in Outlook.

Other Expected Cash Outflows

We plan to make contributions of up to $64 million to our funded pension plans during 2013. As of December 31, 2012, $200 million of commercial paper and $184 million of our long-term debt is due in the next twelve months.

Dividends of $0.68 per common share or $480 million were paid during 2012 reflecting quarterly dividends of $0.17 per share. On January 25, 2013, we announced that our Board of Directors had declared a dividend of $0.17 cents per share on Marathon Oil common stock, payable March 11, 2013, to stockholders of record at the close of business on February 20, 2013.

Share Repurchase Program

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of December 31, 2012, we had repurchased 78 million common shares at a cost of $3,222 million, with 66 million shares purchased for $2,922 million prior to the spin-off of our downstream business and 12 million shares acquired at a cost of $300 million in the third quarter of 2011. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The program's authorization does not include specific price targets or timetables. The timing of purchases under the program will be influenced by cash generated from operations, proceeds from potential asset sales, cash from available borrowings and market conditions.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies. The discussion of liquidity above also contains forward-looking statements regarding expected capital, investment and exploration spending and planned funding of our pension plans. The forward-looking statements about our capital, investment and exploration budget are based on current expectations, estimates and projections and are not guarantees of future performance. The forward-looking statements about our common share repurchase program are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for liquid hydrocarbons, natural gas and synthetic crude oil, actions of competitors, disruptions or interruptions of our production or oil sands mining and bitumen upgrading operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2012.

(In millions)	Total	2013	2014-2015	2016-2017	Later Years
Short and long-term debt (excludes interest)[a]	$ 6,853	$ 384	$ 1,141	$ 688	$ 4,640
Lease obligations	237	43	71	52	71
Purchase obligations:					
Oil and gas activities[b]	993	539	342	47	65
Service and materials contracts[c]	1,139	218	229	174	518
Transportation and related contracts	1,427	210	318	231	668
Drilling rigs and fracturing crews	1,417	709	488	220	—
Other	216	66	80	26	44
Total purchase obligations	5,192	1,742	1,457	698	1,295
Other long-term liabilities reported in the consolidated balance sheet[d]	1,131	122	241	162	606
Total contractual cash obligations[e]	$ 13,413	$ 2,291	$ 2,910	$ 1,600	$ 6,612

[a] We anticipate cash payments for interest of $310 million for 2013, $602 million for 2014-2015, $586 million for 2016-2017 and $2,835 million for the remaining years for a total of $4,333 million.

[b] Oil and gas activities include contracts to acquire property, plant and equipment and commitments for oil and gas exploration such as costs related to contractually obligated exploratory work programs that are expensed immediately.

[c] Service and materials contracts include contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

[d] Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2022. Also includes amounts for uncertain tax positions.

[e] This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,783 million. See Item 8. Financial Statements and Supplementary Data – Note 18 to the consolidated financial statements.

Transactions with Related Parties

We own a 63 percent working interest in the Alba field offshore E.G. Onshore E.G., we own a 52 percent interest in an LPG processing plant, a 60 percent interest in an LNG production facility and a 45 percent interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba field to these equity method investees as the feedstock for their production processes. The methanol that is produced is then sold through another equity method investee.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We will issue stand alone letters of credit when required by a business partner. Such letters of credit outstanding at December 31, 2012, 2011 and 2010 aggregated $139 million, $231 million, and $439 million. Most of the letters of credit are in support of obligations recorded in the consolidated balance sheet. For example, they are issued to counterparties to insure our payments for outstanding company debt, future abandonment liabilities and prior to June 30, 2011, crude purchases by our downstream business which we spun-off on that date. The decline in the level of our outstanding letters of credit in 2011 is primarily related to the spin-off of our downstream business.

Outlook

Our Board of Directors approved a capital, investment and exploration budget of $5,183 million for 2013, including budgeted capital expenditures of $5,003 million. Our focus in 2013 continues to be our U.S. liquids-rich growth assets, with about one-third of our overall budget allocated to the Eagle Ford shale play in south Texas. Further detail of our budget by segment and asset lifecycle is presented below. For additional information about expected exploration and development activities on specific assets see Item 1. Business.

Exploration and Production

Our worldwide E&P budget for 2013 is $4,740 million. Our E&P strategy is based on three key elements: a solid portfolio of base assets that generates significant cash flow, a defined set of growth assets that provides low risk profitable growth and a balanced exploration program targeting significant value creation.

Almost three-fourths, or $3,418 million of the budget is allocated to our growth assets. Of that, $1,940 million is allocated to the Eagle Ford shale play, including planned drilling of 275 - 320 gross (215 - 250 net) operated wells and $190 million for central batteries and pipeline construction. Additionally, we plan to spend nearly $800 million in the Bakken shale in North Dakota and $150 million in the Oklahoma Resource Basins. We plan to drill 190 - 220 gross (65 - 70 net) wells in the Bakken shale and 42 - 50 gross (15 - 19 net) wells in the Oklahoma Resource Basins. Approximately $540 million of our 2013 budget is allocated to other development activities, such as Angola Blocks 31 and 32, the Kurdistan Region of Iraq and Canadian in-situ development.

We plan to spend $872 million on our base E&P assets to provide stable production, income and cash flow. These assets include production operations in Norway, the Gulf of Mexico, U.S. conventional oil and gas plays, E.G., the U.K. and Libya. We will continue to stress a disciplined investment plan and maintain a competitive cost structure, with a continued emphasis on high operational availability, for our base assets.

Our 2013 budget includes $450 million for selective investment in a balanced exploration program. Planned activity will include conducting seismic surveys in Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq, Norway and the deepwater Gulf of Mexico. We plan to drill 10 - 13 gross (3 - 5 net) wells on these prospects and expect to operate three to four of the gross wells.

The above discussion includes forward-looking statements with respect to anticipated future exploratory and development drilling activity, investments in new and existing resource plays, central batteries and pipeline construction projects, and potential development projects. Some factors which could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, drilling rig availability, availability of materials and labor, other risks associated with construction projects, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The foregoing forward-looking statements may be further affected by the inability to obtain or delay in obtaining necessary government and third-party approvals or permits. The development projects could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining

The OSM segment budget for 2013 is $262 million. The 2013 budget includes funds for debottlenecking projects, Quest CCS and other capital expenditures.

Corporate and Other

The remaining $180 million of our 2013 budget is approximately two-thirds capitalized interest on ongoing projects and one-third other corporate activities. Additionally, $1 million is budgeted for our IG segment.

Transactions

Excluded from our budget are the impacts of our acquisitions and dispositions. We continually evaluate ways to optimize our portfolio for profitable growth through acquisitions and dispositions, with a previously stated goal of divesting between $1.5 billion and $3 billion over the period of 2011 through 2013. For the two-year period ended December 31, 2012, we entered into agreements for approximately $1.3 billion in divestitures, of which $785 million were completed. The remaining $545 million of asset sales were completed by February 22, 2013. Additionally, we have engaged in discussions with respect to a potential sale of a portion of our 20 percent interest in the AOSP. Given the uncertainty of such a transaction, potential proceeds have not been included in our previously stated divestiture goal.

The forward-looking statements about our capital, investment and exploration budget and the goal of divesting between $1.5 and $3 billion of assets over the period of 2011 through 2013 are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for crude oil and natural gas, actions of competitors, disruptions or interruptions of our production or bitumen mining and upgrading operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations.

The above discussion also contains forward-looking statements with regard to discussions with respect to a potential sale of a portion of our 20 percent interest in the AOSP. The potential sale of a portion of our interest in the AOSP is subject to successful negotiations and execution of definitive agreements. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies

We have incurred and may continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas, and production processes.

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to materially adversely impact our business, financial condition, results of operations and cash flows, including costs of compliance and permitting delays. The extent and magnitude of these adverse impacts cannot be reliably or accurately estimated at this time because specific regulatory and legislative requirements have not been finalized and uncertainty exists with respect to the measures being considered, the costs and the time frames for compliance, and our ability to pass compliance costs on to our customers. For additional information see Item 1A. Risk Factors.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required. For additional information see Item 8. Financial Statements and Supplementary Data – Note 24 to the consolidated financial statements.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We comply with all legal requirements regarding the environment, but since not all costs are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

For more information on environmental regulations that impact us, or could impact us, see Item 1. Business – Environmental, Health and Safety Matters, Item 3. Legal Proceedings and Item 1A. Risk Factors.

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Estimated Quantities of Net Reserves

The estimation of quantities of net reserves is a highly technical process performed by our engineers for liquid hydrocarbons and natural gas, and by outside consultants for synthetic crude oil, which is based upon several underlying assumptions that are subject to change. Estimates of reserves may change, either positively or negatively, as additional information becomes available and as contractual, operational, economic and political conditions change. We evaluate our reserves using drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Reserve estimates are based upon an unweighted average of commodity prices in the prior 12-month period, using the closing prices on the first day of each month. These prices are not indicative of future market conditions. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business.

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved liquid hydrocarbon, natural gas and synthetic crude oil reserves.

The existence and the estimated amount of reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. Additionally, both the expected future cash flows to be generated by oil and gas producing properties used in testing such properties for impairment and the expected future taxable income available to realize deferred tax assets also rely, in part, on estimates of quantities of net reserves.

Depreciation and depletion of liquid hydrocarbon, natural gas and synthetic crude oil producing properties is determined by the units-of-production method and could change with revisions to estimated proved reserves. Over the past three years, the impact on our depreciation and depletion rate due to revisions of previous reserve estimates has not been significant to either our E&P or our OSM segments. For our E&P segment, on average, a five percent increase in the amount of proved liquid hydrocarbon and natural gas reserves would lower the depreciation and depletion rate by approximately $0.67 per boe, which would increase pretax income by approximately $106 million annually, based on 2012 production. Conversely, on average, a five percent decrease in the amount of proved liquid hydrocarbon and natural gas reserves would increase the depreciation and depletion rate by approximately $0.74 per boe and would result in a decrease in pretax income of approximately $117 million annually, based on 2012 production. For our OSM segment, on average, a five percent increase in estimated proved synthetic crude oil reserves would lower the depreciation and depletion rate by approximately $0.86 per barrel and would result in an increase in pretax income of approximately $13 million annually, based on 2012 production. On average, a five percent decrease in estimated proved synthetic crude oil reserves would increase the depreciation and depletion rate by approximately $0.38 per barrel and would result in a decrease in pretax income of approximately $6 million annually, based on 2012 production.

Fair Value Estimates

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 at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.

- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. We use a market or income approach for recurring fair value measurements and endeavor to use the best information available. See Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- impairment assessments of goodwill;
- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed; and
- recorded value of derivative instruments.

Impairment Assessments of Long-Lived Assets and Goodwill

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of liquid hydrocarbons, natural gas or synthetic crude oil, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which the property is located.

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field for E&P assets and at the project level for OSM assets. If the sum of the undiscounted estimated pretax cash flows is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value.

Unlike long-lived assets, goodwill must be tested for impairment at least annually, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Goodwill is tested for impairment at the reporting unit level.

Fair value calculated for the purpose of testing our long-lived assets and goodwill for impairment is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- **Future liquid hydrocarbon, natural gas and synthetic crude oil prices.** Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates, and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies, and vehicle stocks. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in liquid hydrocarbon, natural gas and synthetic crude oil prices and estimates of such future prices are inherently imprecise.

- **Estimated quantities of liquid hydrocarbons, natural gas and synthetic crude oil.** Such quantities are based on a combination of proved and probable reserves such that the combined volumes represent the most likely expectation of recovery. By definition, probable reserve estimates are less precise than proved reserve estimates.

- **Expected timing of production.** Production forecasts are the outcome of engineer studies which estimate proved and probable reserves. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.

- *Discount rate commensurate with the risks involved*. We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.

- **Future capital requirements.** Our estimates of future capital requirements are based on authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g. reserves, pricing and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Acquisitions

In accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values of property, plant and equipment and identifiable intangible assets. The most significant assumptions relate to the estimated fair values allocated to proved and unproved liquid hydrocarbon, natural gas and synthetic crude oil properties. Estimated fair values assigned to assets acquired can have a significant effect on our results of operations in the future. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance. During 2011 and 2012, we completed several business combinations in the Eagle Ford shale that were allocated to the assets acquired and liabilities assumed based on their estimated fair values (see Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements).

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to estimate reserves as described above under Estimated Quantities of Net Reserves, project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Derivatives

We record all derivative instruments at fair value. Fair value estimates for all our derivative instruments are based on observable market-based inputs that are corroborated by market data and are discussed in Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Income Taxes

We are subject to income taxes in numerous taxing jurisdictions worldwide. Estimates of income taxes to be recorded involve interpretation of complex tax laws and assessment of the effects of foreign taxes on our U.S. federal income taxes.

We have recorded deferred tax assets and liabilities for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider the preponderance of evidence concerning the realization of the deferred tax asset. We must consider any prudent and feasible tax planning strategies that might minimize the amount of deferred tax liabilities recognized or the amount of any valuation allowance recognized against deferred tax assets, if we can implement the strategies and we expect to implement them in the event the forecasted conditions actually occur. Assumptions related to the permanent reinvestment of the earnings of our foreign subsidiaries are reconsidered quarterly to give effect to changes in our portfolio of producing properties and in our tax profile.

Our net deferred tax assets, after valuation allowances, are expected to be realized through our future taxable income and the reversal of temporary differences. Numerous judgments and assumptions are inherent in the estimation of future taxable income, including factors such as future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices) and the assessment of the effects of foreign taxes on our U.S. federal income taxes. The estimates and assumptions used in determining future taxable income are consistent with those used in our planning and capital investment reviews. We consider proved and, in some cases, probable and possible reserves related to our existing producing properties, as well as estimated quantities of liquid hydrocarbon, natural gas and synthetic crude oil related to undeveloped discoveries if, in our judgment, it is likely that development plans will be approved in the foreseeable future. Assumptions regarding our ability to realize the U.S. federal benefit of foreign tax credits are based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the year that such credits may be claimed.

Pension and Other Postretirement Benefit Obligations

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets;
- the rate of future increases in compensation levels; and
- health care cost projections.

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our funded U.S. pension plans and our unfunded U.S. retiree health care plans due to the different projected benefit payment patterns. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary's discount rate model. This model calculates an equivalent single discount rate for the projected benefit plan cash flows using a yield curve derived from AA bond yields. The yield curve represents a series of annualized individual spot discount rates from 0.5 to 99 years. The bonds used are rated AA or higher by a recognized rating agency, only non-callable bonds are included and outlier bonds (bonds that have a yield to maturity that significantly deviates from the average yield within each maturity grouping) are removed. Each issue is required to have at least $250 million par value outstanding. The constructed yield curve is based on those bonds representing the 50 percent highest yielding issuance within each defined maturity group.

Of the assumptions used to measure the yearend obligations and estimated annual net periodic benefit cost, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. Decreasing the discount rates of 3.44 percent for our U.S. pension plans and 4.06 percent for our other U.S. postretirement benefit plans by 0.25 would increase pension obligations and other postretirement benefit plan obligations by $52 million and $9 million and would increase annual defined benefit pension expense by $5 million and would not have a significant impact on other postretirement benefit plan expense.

The asset rate of return assumption considers the asset mix of the plans (currently targeted at approximately 65 percent equity and high yield bonds and 35 percent other fixed income securities for the U.S. funded pension plans and 70 percent equity securities and 30 percent fixed income securities for the international funded pension plans), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. Our long-term asset rate of return assumption is compared to those of other companies and to our historical returns for reasonableness. Decreasing the 7.25 percent asset rate of return assumption by 0.25 would not have a significant impact on our defined benefit pension expense.

Compensation change assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans. Health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

Item 8. Financial Statements and Supplementary Data – Note 20 to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the balance sheets.

Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes, and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation; additional information on the extent and nature of site contamination; and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances, outside legal counsel is utilized.

We generally record losses related to these types of contingencies as cost of revenues or general and administrative expenses in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as other taxes. For additional information on contingent liabilities, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Management’s Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

Accounting Standards Not Yet Adopted

In February 2013, an accounting standards update was issued to improve the reporting of reclassifications out of accumulated other comprehensive income. This standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. These disclosures are effective for us beginning the first quarter of 2013. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In December 2011 an accounting standards update designed to enhance disclosures about offsetting assets and liabilities was issued. Further clarification limiting the scope of these disclosures to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions was issued in January 2013. The disclosures are intended to enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity's financial position. Entities are required to disclose both gross information and net information about in-scope financial instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. These disclosures are effective for us beginning the first quarter of 2013 and must be made retrospectively for comparable periods. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risks related to the volatility of liquid hydrocarbon, natural gas and synthetic crude oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. We are also exposed to market risks related to changes in interest rates and foreign currency exchange rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction.

We believe that our use of derivative instruments, along with our risk assessment procedures and internal controls, does not expose us to material adverse consequences. While the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity.

See Item 8. Financial Statements and Supplementary Data – Note 15 and 16 to the consolidated financial statement for more information about the fair value measurement of our derivatives, as well as the amounts recorded in our consolidated balance sheets and statements of income for those which qualify as hedges and those not designated as hedges.

Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management will occasionally protect prices on forecasted sales, as deemed appropriate. We use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our different businesses. In August 2012, we entered into crude oil derivatives related to a portion of our forecast U.S. E&P crude oil sales through December 31, 2013 as shown in the table below.

Remaining Term	Bbls per Day	Weighted Average Price per Bbl	Benchmark
Swaps			
January 2013 - December 2013	20,000	$96.29	West Texas Intermediate
January 2013 - December 2013	25,000	$109.19	Brent
Option collars			
January 2013 - December 2013	15,000	$90.00 floor / $101.17 ceiling	West Texas Intermediate
January 2013 - December 2013	15,000	$100.00 floor / $116.30 ceiling	Brent

We regularly use commodity derivative instruments in the E&P segment to manage natural gas price risk during the time that the natural gas is held in storage before it is sold or related to our supply optimization activities. We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles.

Sensitivity analysis of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent increases and decreases in commodity prices on our open commodity derivative instruments, by contract type as of December 31, 2012 is provided in the following table.

	Incremental Change in IFO from a Hypothetical Price Increase of		Incremental Change in IFO from a Hypothetical Price Decrease of	
	10%	25%	10%	25%
Crude oil				
Swaps	$ (165)	$ (412)	$ 165	$ 412
Option collars	(77)	(212)	77	246
Total crude oil	(242)	(624)	242	658
Natural gas				
Futures	(1)	(2)	1	2

Total natural gas	(1)	(2)	1	2
Total	$ (243)	$ (626)	$ 243	$ 660

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the mix of fixed and floating interest rate debt in our portfolio. As of December 31, 2012, we had multiple interest rate swap agreements with a total notional amount of $600 million at a weighted-average, LIBOR-based, floating rate of 4.70 percent with a maturity date of October 1, 2017. These interest rate swaps are designated as fair value hedges, which effectively results in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates.

Sensitivity analysis of the incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of December 31, 2012, is provided in the following table.

(In millions)		Fair Value		Incremental Change in Fair Value
Financial assets (liabilities): [(a)]				
Interest rate swap agreements	$	21 [(b)]	$	1
Long-term debt, including amounts due within one year	$	(7,610) [(b)]	$	(232)

[(a)] Fair values of cash and cash equivalents, receivables, commercial paper, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.

[(b)] Fair value was based on market prices where available, or current borrowing rates for financings with similar terms and maturities.

At December 31, 2012, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

Foreign Currency Exchange Rate Risk

We may manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. As of December 31, 2012, our foreign currency forwards had an aggregate notional amount of 3,043 million Norwegian Kroner at a weighted average forward rate of 5.780. These forwards hedge our current Norwegian tax liability and have settlement dates through June 2013. The incremental change in fair value on foreign currency derivative contracts of a hypothetical 10 percent change in exchange rates at December 31, 2012 would be $54 million.

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is reviewed and master netting agreements are used when appropriate.

Safe Harbor

These quantitative and qualitative disclosures about market risk include forward-looking statements with respect to management's opinion about risks associated with the use of derivative instruments. These statements are based on certain assumptions with respect to market prices and industry supply of and demand for liquid hydrocarbons, natural gas and synthetic crude oil. If these assumptions prove to be inaccurate, future outcomes with respect to our use of derivative instruments may differ materially from those discussed in the forward-looking statements.

Item 8. Financial Statements and Supplementary Data

Index

Management's Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries ("Marathon Oil") are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the United States. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon Oil seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organization arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Clarence P. Cazalot, Jr.	/s/ Janet F. Clark	/s/ Michael K. Stewart
Chairman, President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*	*Vice President, Finance and Accounting, Controller and Treasurer*

Management's Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon Oil's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13(a) – 15(f) under the Securities Exchange Act of 1934). An evaluation of the design and effectiveness of our internal control over financial reporting, based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon Oil's management concluded that its internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of Marathon Oil's internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Clarence P. Cazalot, Jr.	/s/ Janet F. Clark
Chairman, President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*

Report of Independent Registered Public Accounting Firm

To the Stockholders of Marathon Oil Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Marathon Oil Corporation and its subsidiaries (the "Company") at December 31, 2012, and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company'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 Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Houston, Texas
February 22, 2013

MARATHON OIL CORPORATION
Consolidated Statements of Income

(In millions, except per share data)	2012	2011	2010
Revenues and other income:			
Sales and other operating revenues	$ 15,630	$ 14,603	$ 11,634
Sales to related parties	58	60	56
Income from equity method investments	370	462	344
Net gain on disposal of assets	127	103	766
Other income	36	54	73
Total revenues and other income	16,221	15,282	12,873
Costs and expenses:			
Cost of revenues (excludes items below)	5,219	6,225	4,786
Purchases from related parties	248	250	172
Depreciation, depletion and amortization	2,478	2,266	2,056
Impairments	371	310	447
General and administrative expenses	555	544	491
Other taxes	289	230	199
Exploration expenses	729	644	498
Total costs and expenses	9,889	10,469	8,649
Income from operations	6,332	4,813	4,224
Net interest and other	(219)	(107)	(75)
Loss on early extinguishment of debt	—	(279)	(92)
Income from continuing operations before income taxes	6,113	4,427	4,057
Provision for income taxes	4,531	2,720	2,175
Income from continuing operations	1,582	1,707	1,882
Discontinued operations	—	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568
Per Share Data			
Basic:			
Income from continuing operations	$ 2.24	$ 2.40	$ 2.65
Discontinued operations	$ —	$ 1.75	$ 0.97
Net income	$ 2.24	$ 4.15	$ 3.62
Diluted:			
Income from continuing operations	$ 2.23	$ 2.39	$ 2.65
Discontinued operations	$ —	$ 1.74	$ 0.96
Net income	$ 2.23	$ 4.13	$ 3.61
Dividends	$ 0.68	$ 0.80	$ 0.99
Weighted average shares:			
Basic	706	710	710
Diluted	710	714	712

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION

Consolidated Statements of Comprehensive Income

(In millions)	2012	2011*	2010
Net income	$ 1,582	$ 2,946	$ 2,568
Other comprehensive income (loss)			
Postretirement and postemployment plans			
Change in actuarial loss and other	(97)	16	(76)
Income tax benefit on postretirement and postemployment plans	35	20	7
Postretirement and postemployment plans, net of tax	(62)	36	(69)
Derivative hedges			
Net unrecognized gain	1	9	5
Income tax benefit (provision) on derivative hedges	—	(4)	1
Derivative hedges, net of tax	1	5	6
Foreign currency translation and other			
Unrealized gain (loss)	1	(1)	—
Income tax provision on foreign currency translation and other	(3)	—	—
Foreign currency translation and other, net of tax	(2)	(1)	—
Other comprehensive income (loss)	(63)	40	(63)
Comprehensive income	$ 1,519	$ 2,986	$ 2,505

*See Note 1 – Summary of Principal Accounting Policies – Revision for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Balance Sheets

(In millions, except per share data)	December 31, 2012	2011
Assets		
Current assets:		
Cash and cash equivalents	$ 684	$ 493
Receivables	2,389	1,917
Receivables from related parties	27	35
Inventories	361	361
Other current assets	301	418
Total current assets	3,762	3,224
Equity method investments	1,279	1,383
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $19,266 and $17,248	28,272	25,324
Goodwill	525	536
Other noncurrent assets	1,468	904
Total assets	$ 35,306	$ 31,371
Liabilities		
Current liabilities:		
Commercial paper	$ 200	$ —
Accounts payable	2,285	1,864
Payables to related parties	20	18
Payroll and benefits payable	217	193
Accrued taxes	1,987	2,015
Other current liabilities	188	163
Long-term debt due within one year	184	141
Total current liabilities	5,081	4,394
Long-term debt	6,512	4,674
Deferred tax liabilities	2,432	2,544
Defined benefit postretirement plan obligations	856	789
Asset retirement obligations	1,749	1,510
Deferred credits and other liabilities	393	301
Total liabilities	17,023	14,212
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 770 million and 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Securities exchangeable into common stock – no shares issued or outstanding (no par value, 29 million shares authorized)	—	—
Held in treasury, at cost – 63 million and 66 million shares	(2,560)	(2,716)

Additional paid-in capital	6,616	6,680
Retained earnings	13,890	12,788
Accumulated other comprehensive loss	(433)	(370)
Total equity of Marathon Oil stockholders	18,283	17,152
Noncontrolling interest	—	7
Total equity	18,283	17,159
Total liabilities and equity	$ 35,306	$ 31,371

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

(In millions)	2012	2011	2010
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$ 1,582	$ 2,946	$ 2,568
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations	—	(1,239)	(686)
Loss on early extinguishment of debt	—	279	92
Deferred income taxes	(210)	(182)	(489)
Depreciation, depletion and amortization	2,478	2,266	2,056
Impairments	371	310	447
Pension and other postretirement benefits, net	(31)	64	31
Exploratory dry well costs and unproved property impairments	457	357	225
Net gain on disposal of assets	(127)	(103)	(766)
Equity method investments, net	11	47	56
Changes in:			
Current receivables	(499)	8	(409)
Inventories	(34)	33	(71)
Current accounts payable and accrued liabilities	96	485	1,018
All other operating, net	(77)	163	122
Net cash provided by continuing operations	4,017	5,434	4,194
Net cash provided by discontinued operations	—	1,090	1,676
Net cash provided by operating activities	4,017	6,524	5,870
Investing activities:			
Acquisitions, net of cash acquired	(1,033)	(4,470)	—
Additions to property, plant and equipment	(4,940)	(3,295)	(3,536)
Disposal of assets	467	518	1,368
Investments - return of capital	57	59	58
Investing activities of discontinued operations	—	(493)	(464)
All other investing, net	10	14	(47)
Net cash used in investing activities	(5,439)	(7,667)	(2,621)
Financing activities:			
Commercial paper, net	200	—	—
Borrowings	1,997	—	—
Debt issuance costs	(21)	—	—
Debt repayments	(145)	(2,877)	(653)
Purchases of common stock	—	(300)	—
Dividends paid	(480)	(567)	(704)
Financing activities of discontinued operations	—	2,916	(12)
Distribution in spin-off	—	(1,622)	—
All other financing, net	49	155	14
Net cash provided by (used in) financing activities	1,600	(2,295)	(1,355)
Effect of exchange rate changes on cash	13	(20)	—

Net increase (decrease) in cash and cash equivalents	191	(3,458)	1,894
Cash and cash equivalents at beginning of period	493	3,951	2,057
Cash and cash equivalents at end of period	$ 684	$ 493	$ 3,951

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

	Total Equity of Marathon Oil Stockholders								
(In millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total Equity
January 1, 2010 Balance	$ —	$ 769	$ —	$ (2,706)	$ 6,738	$ 18,043	$ (934)	$ —	$ 21,910
Shares issued - stock based compensation	—	—	—	46	(12)	—	—	—	34
Shares exchanged	—	1	—	—	(1)	—	—	—	—
Shares repurchased	—	—	—	(5)	—	—	—	—	(5)
Stock-based compensation	—	—	—	—	31	—	—	—	31
Net income	—	—	—	—	—	2,568	—	—	2,568
Other comprehensive loss	—	—	—	—	—	—	(63)	—	(63)
Dividends paid	—	—	—	—	—	(704)	—	—	(704)
December 31, 2010 Balance	$ —	$ 770	$ —	$ (2,665)	$ 6,756	$ 19,907	$ (997)	$ —	$ 23,771
Shares issued - stock based compensation	—	—	—	257	(85)	—	—	—	172
Shares repurchased	—	—	—	(308)	—	—	—	—	(308)
Stock-based compensation	—	—	—	—	4	—	—	—	4
Net income	—	—	—	—	—	2,946	—	—	2,946
Other comprehensive income	—	—	—	—	—	—	40	—	40
Dividends paid	—	—	—	—	—	(567)	—	—	(567)
Purchase of subsidiary shares from non-controlling interest	—	—	—	—	—	—	—	7	7
Spin-off of downstream business	—	—	—	—	5	(9,498)	587	—	(8,906)
December 31, 2011 Balance	$ —	$ 770	$ —	$ (2,716)	$ 6,680	$ 12,788	$ (370)	$ 7	$ 17,159
Shares issued - stock based compensation	—	—	—	164	(75)	—	—	—	89
Shares repurchased	—	—	—	(8)	—	—	—	—	(8)
Stock-based compensation	—	—	—	—	22	—	—	—	22
Net income	—	—	—	—	—	1,582	—	—	1,582
Other comprehensive loss	—	—	—	—	—	—	(63)	—	(63)
Dividends paid	—	—	—	—	—	(480)	—	—	(480)
Purchase of subsidiary shares from non-controlling interest	—	—	—	—	—	—	—	(7)	(7)
Other	—	—	—	—	(11)	—	—	—	(11)
December 31, 2012 Balance	$ —	$ 770	$ —	$ (2,560)	$ 6,616	$ 13,890	$ (433)	$ —	$ 18,283

(Shares in millions)	Preferred	Common	Securities	Treasury

	Stock	Stock	Exchangeable into Common Stock	Stock
January 1, 2010 Balance	1	769	1	(61)
Shares issued - stock based compensation	—	—	—	1
Shares exchanged	(1)	1	(1)	—
December 31, 2010 Balance	—	770	—	(60)
Shares issued - stock based compensation	—	—	—	6
Shares repurchased	—	—	—	(12)
December 31, 2011 Balance	—	770	—	(66)
Shares issued - stock based compensation	—	—	—	3
Shares repurchased	—	—	—	—
December 31, 2012 Balance	—	770	—	(63)

The accompanying notes are an integral part of these consolidated financial statements.

1. Summary of Principal Accounting Policies

We are engaged in worldwide exploration, production and marketing of liquid hydrocarbons and natural gas; oil sands mining, bitumen transportation and upgrading, marketing of synthetic crude oil and vacuum gas oil in Canada; and production and marketing of products manufactured from natural gas, such as LNG and methanol in E.G.

Principles applied in consolidation – These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries and variable interest entities for which we are the primary beneficiary.

Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority stockholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees.

Equity method investments are carried at our share of net assets plus loans and advances. Such investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in net income. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

As a result of the spin-off of our downstream business (see Note 3), the results of operations and cash flows for the downstream business have been classified as discontinued operations for 2011 and 2010. The disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated.

Use of estimates – The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Revision – We have revised our 2011 consolidated statement of comprehensive income to exclude the effects of the spin-off of our former downstream business. Changes in accumulated other comprehensive loss of $587 million, net of tax, associated with postretirement and postemployment plans ($591 million, net of tax) and unrecognized derivative hedging losses ($4 million, net of tax) related to the downstream business were removed from this statement. The revision had no impact on our consolidated balance sheets or consolidated statements of income, cash flows or stockholders' equity for any periods presented.

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. Costs associated with revenues are recorded in cost of revenues.

In the lower 48 states of the U.S., production volumes of liquid hydrocarbons and natural gas are sold immediately and transported to market. In Alaska and international locations, liquid hydrocarbon and natural gas production volumes may be stored as inventory and sold at a later time. In Canada, mined bitumen is first processed through an upgrader and then sold as synthetic crude oil. Both bitumen and synthetic crude oil may be stored as inventory.

We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

Cash and cash equivalents – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable – The majority of our receivables are from joint interest owners in properties we operate, or from purchasers of commodities, both of which are recorded at invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. Uncollectible accounts receivable are reserved against the allowance for uncollectible accounts when it is determined the receivable will not be collected and the amount of any reserve may be reasonably estimated.

Inventories – Inventories are carried at the lower of cost or market value. The majority of our inventories are recorded at average cost. The last-in, first-out ("LIFO") method is used for our U.S. crude oil and natural gas inventories.

We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

Derivative instruments – We may use derivatives to manage a portion of our exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk. All derivative instruments are recorded at fair value. Commodity derivatives are reflected on our consolidated balance sheet on a net basis by brokerage firm, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, interest rate risk and foreign currency exchange rate risk related to operating expenditures are classified in operating activities with the underlying transactions. Cash flows related to derivatives used to manage exchange rate risk related to capital expenditures denominated in foreign currencies are classified in investing activities with the underlying transactions. Our derivative instruments contain no significant contingent credit features.

Cash flow hedges – We may use foreign currency forwards and options to manage foreign currency risk associated with anticipated transactions, primarily expenditures for capital projects denominated in certain foreign currencies, and designate them as cash flow hedges. The effective portion of changes in fair value is recognized in other comprehensive income ("OCI") and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion is recognized in net interest and other as it occurs. For a discontinued cash flow hedge, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2012 and 2011.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio; commodity derivative instruments to manage the price risk on natural gas that we purchase to be marketed with our natural gas production; and foreign currency forwards to manage our exposure to changes in the value of foreign currency denominated tax liabilities. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Derivatives not designated as hedges – Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price risk on the forecasted sale of crude oil, natural gas and synthetic crude oil that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Concentrations of credit risk – All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

Property, plant and equipment – We use the successful efforts method of accounting for oil and gas producing activities, which include bitumen mining and upgrading.

Property acquisition costs – Costs to acquire mineral interests in traditional oil and natural gas properties or in oil sands mines, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and to construct or expand oil sands mines and upgrading facilities are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties, which include our bitumen mining and upgrading facilities, are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities are depreciated on a straight-line basis over their estimated useful lives which range from 3 to 43 years.

Property, plant and equipment unrelated to oil and gas producing activities is recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 40 years.

Impairments – We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells, development costs and our bitumen mining and upgrading facilities, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure. Impairment of proved properties is required when the carrying value exceeds the related undiscounted future net cash flows based on proved and probable reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors and may apply an undiscounted future net cash flow approach when appropriate. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage are also considered. When unproved property investments are deemed to be impaired the expense is reported in exploration expenses.

Dispositions – When property, plant and equipment depreciated on an individual basis are sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

Goodwill – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

Major maintenance activities – Costs for planned major maintenance are expensed in the period incurred. These types of costs include contractor repair services, materials and supplies, equipment rentals and our labor costs.

Environmental costs – Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed and determinable.

Asset retirement obligations – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities, which include our bitumen mining facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, mine assets, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals. Asset retirement obligations have not been recognized for certain of our international oil and gas producing facilities as we currently do not have a legal obligation associated with the retirement of those facilities. Asset retirement obligations have not been recognized for the removal of materials and equipment from or the closure of certain bitumen upgrading assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate.

Current inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time.

Depreciation is generally determined on a units-of-production basis for oil and gas production facilities, which include our bitumen mining facilities, while accretion escalates over the lives of the assets.

Deferred income taxes – Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management's intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

Stock based compensation arrangements – The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of our stock price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards and common stock units is determined based on the market value of our common stock on the date of grant. Unearned stock-based compensation is charged to stockholders' equity when restricted stock awards are granted.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods. Options with tandem SARs are classified as a liability and are remeasured at fair value each reporting period until settlement.

Fair value transfer – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. When significant transfers occur, they are disclosed in the appropriate footnote to the financial statements.

2. Accounting Standards

Not Yet Adopted

In February 2013, an accounting standards update was issued to improve the reporting of reclassifications out of accumulated other comprehensive income. This standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. These disclosures are effective for us beginning the first quarter of 2013. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In December 2011 an accounting standards update designed to enhance disclosures about offsetting assets and liabilities was issued. Further clarification limiting the scope of these disclosures to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions was issued in January 2013. The disclosures are intended to enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity's financial position. Entities are required to disclose both gross information and net information about in-scope financial instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. These disclosures are effective for us beginning the first quarter of 2013 and must be made retrospectively for comparable periods. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In September 2011, the FASB amended accounting standards to simplify how entities test goodwill for impairment. The amendment reduces complexity by allowing an entity the option to make a qualitative evaluation of whether it is necessary to perform the two-step goodwill impairment test. The amendment was effective for our interim and annual periods beginning with the first quarter of 2012. Adoption of this amendment did not have a significant impact on our consolidated results of operations, financial position or cash flows.

The FASB amended the reporting standards for comprehensive income in June 2011 to eliminate the option to present the components of OCI as part of the statement of changes in stockholders' equity. All non-owner changes in stockholders' equity are required to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of OCI, and total comprehensive income. The presentation of items that are reclassified from OCI to net income on the income statement is also required. The amendments did not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The amendments were effective for us beginning with the first quarter of 2012, except for the presentation of reclassifications, which was deferred and addressed in the February 2013 accounting standards update discussed above. Adoption of these amendments did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2011, the FASB issued an update amending the accounting standards for fair value measurement and disclosure, resulting in common principles and requirements under U.S. GAAP and IFRS. The amendments change the wording used to describe certain of the U.S. GAAP requirements either to clarify the intent of existing requirements, to change measurement or expand disclosure principles or to conform to the wording used in IFRS. The amendments were to be applied prospectively for our interim and annual periods beginning with the first quarter of 2012. The adoption of the amendments did not have a significant impact on our consolidated results of operations, financial position or cash flows. To the extent they were necessary, we made the expanded disclosures in Notes 15 and 20.

3. Spin-off of Downstream Business

On June 30, 2011, the spin-off of Marathon's downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. On June 30, 2011, stockholders of record as of 5:00 p.m. Eastern Daylight Savings time on June 27, 2011 (the "Record Date") received one common share of MPC stock for every two common shares of Marathon stock held as of the Record Date.

In order to effect the spin-off and govern our relationship with MPC after the spin-off, we entered into a Separation and Distribution Agreement, a Tax Sharing Agreement and an Employee Matters Agreement. The Separation and Distribution Agreement governed the separation of the downstream business, the distribution of MPC's shares of common stock to our stockholders, transfer of assets and intellectual property, and other matters related to our relationship with MPC. The Separation and Distribution Agreement provides for cross-indemnities between Marathon Oil and MPC. In general, we have agreed to indemnify MPC for any liabilities relating to our historical E&P operations, OSM operations and IG operations, and MPC has agreed to indemnify us for any liabilities relating to the historical downstream operations.

The Tax Sharing Agreement governs the respective rights, responsibilities and obligations of Marathon Oil and MPC with respect to taxes and tax benefits, the filing of tax returns, the control of audits and other tax matters. In addition, the Tax Sharing Agreement reflects each company's rights and obligations related to taxes that are attributable to periods prior to and including the separation date and taxes resulting from transactions effected in connection with the separation. In general, under the Tax Sharing Agreement, Marathon Oil is responsible for all U.S. federal, state, local and foreign income taxes attributable to Marathon Oil or any of its subsidiaries for any tax period that begins after the date of the spin-off, and MPC is responsible for all taxes attributable to it or its subsidiaries, whether accruing before, on or after the spin-off. The Tax Sharing Agreement contains covenants intended to protect the tax-free status of the spin-off. These covenants may restrict the ability of Marathon Oil and MPC to pursue strategic or other transactions that otherwise could maximize the values of their respective businesses and may discourage or delay a change of control of either company.

The Employee Matters Agreement contains provisions concerning benefit protection for employees who became MPC employees prior to December 31, 2011, treatment of holders of Marathon stock options, stock appreciation rights, restricted stock and restricted stock units, and cooperation between Marathon Oil and MPC in the sharing of employee information and maintenance of confidentiality. Unvested equity-based compensation awards were converted to awards of the entity where the employee holding them worked post-separation. For vested equity-based compensation awards, employees received both Marathon Oil and MPC awards.

The results of operations of our downstream business have been reported as discontinued operations for 2011 and 2010. The table below shows selected financial information reported in discontinued operations related to the spin-off.

(In millions)	2011	2010
Revenues applicable to discontinued operations	$ 38,602	$ 62,488

Pretax income from discontinued operations	$	2,012	$	1,065

4. Variable Interest Entities

The owners of the AOSP, in which we hold a 20 percent undivided interest, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with a $3 million current liability recorded at December 31, 2012, consistent with December 31, 2011. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a variable interest entity ("VIE"). We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore the Corridor Pipeline is not consolidated by Marathon Oil. Our maximum exposure to loss as a result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $694 million as of December 31, 2012. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month’s activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

5. Acquisitions

During 2012 and 2011, our significant business combinations related to properties acquired by our E&P segment in the Eagle Ford shale in south Texas. The pro forma impact of these transactions, individually and in the aggregate, is not material to our consolidated statements of income for any periods presented.

The fair values of assets acquired and liabilities assumed in each of these business combinations were measured primarily using an income approach, specifically utilizing a discounted cash flow analysis. The estimated fair values were based on significant inputs not observable in the market, and therefore represent Level 3 measurements. Significant inputs included estimated reserve volumes, the expected future production profile, estimated commodity prices and assumptions regarding future operating and development costs. The discount rates used in the discounted cash flow analyses were approximately 10 percent for the 2012 transactions and 11 percent for the 2011 transaction.

2012

We acquired approximately 25,000 net acres in the core of the Eagle Ford shale during 2012. The largest transactions were the acquisitions of Paloma Partners II, LLC, which closed August 1, 2012 for cash consideration of $768 million, and an acquisition of proved and unproved properties that closed on November 1, 2012 for cash consideration of $232 million. These transactions were accounted for as business combinations.

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

	Acquisition Date	
(In millions)	August 1, 2012	November 1, 2012
Current assets:		
Cash	$ 8	$ —
Receivables	22	8
Inventories	1	—
Total current assets acquired	31	8
Property, plant and equipment	822	248
Total assets acquired	$ 853	$ 256
Current liabilities:		
Accounts payable	78	23
Total current liabilities assumed	78	23
Asset retirement obligations	7	1
Total liabilities assumed	85	24
Net assets acquired	$ 768	$ 232

2011

During the fourth quarter of 2011, we closed a series of transactions in the Eagle Ford shale that were accounted for as a business combination. The most significant of these transactions was the acquisition of Hilcorp Resources, LLC. The total cash consideration paid for all the transactions including approximately 167,000 net acres and a gathering system, was $4.5 billion which was funded from existing cash.

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

(In millions)	
Current assets:	
Receivables	$ 40
Inventories	4
Other current assets	30
Total current assets acquired	74
Property, plant and equipment	4,501
Other noncurrent assets	21
Total assets acquired	$ 4,596
Current liabilities:	
Accounts payable	$ 101
Other current liabilities	20
Total current liabilities assumed	121
Asset retirement obligations	5
Total liabilities assumed	126
Net assets acquired	$ 4,470

In addition, during 2011,our E&P segment acquired approximately 108,000 net acres in the Eagle Ford shale for approximately $265 million. These transactions were funded from existing cash and were accounted for as asset acquisitions.

6. Dispositions

2013

In February 2013, we entered an agreement to convey our interest in the Marcellus natural gas shale play to the operator.

2012

Neptune gas plant – In December 2012, we entered into an agreement to sell our our E&P segment's interest in the Neptune gas plant, located onshore Louisiana. The transaction, with a value of $170 million before closing adjustments, closed in February 2013.

Eagle Ford acreage – In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres located outside the core of the Eagle Ford shale, held by our E&P segment, for proceeds of $9 million. A pretax loss of $18 million was recorded.

Indonesia – In May 2012, we executed agreements to relinquish our E&P segment's operatorship of, and participating interests in, the Bone Bay and Kumawa exploration licenses in Indonesia. As a result, we reported a $36 million loss on disposal of assets. Government ratification of the agreements released us from our obligations and further commitments related to these licenses.

Alaska – In April 2012, we entered into agreements to sell all of our E&P segment's assets in Alaska. One transaction closed in 2012 with proceeds and a net gain of $7 million. The second transaction closed in January 2013, for proceeds of $195 million subject to a six-month escrow of $50 million for various indemnities.

Gulf of Mexico pipelines – In January 2012, we closed on the sale of our E&P segment's interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This included our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded.

Assets held for sale in the December 31, 2012 consolidated balance sheet were related to the Neptune gas plant and Alaska dispositions that were pending at that date and included:

(In millions)		
Other current assets	$	50
Other noncurrent assets		248
Total assets	$	298
Deferred credits and other liabilities		83
Total liabilities	$	83

2011

Burns Point gas plant – In December 2011, we sold our E&P segment's 50 percent interest in the Burns Point gas plant, a cryogenic processing plant located in St. Mary Parish, Louisiana, for total consideration of $36 million and a pretax gain of $34 million.

Alaska LNG facility – In September 2011, we sold our IG segment's equity interest in an LNG processing facility in Alaska and a pretax gain on the transaction of $8 million was recorded.

DJ Basin – In April 2011, we assigned a 30 percent undivided working interest in the approximately 180,000 acres then held by our E&P segment in the Niobrara shale play located within the DJ Basin of southeast Wyoming and northern Colorado for total consideration of $270 million, recording a pretax gain of $37 million. We remain operator of this jointly owned leasehold.

2010

Angola – In February 2010, we closed the sale of a 20 percent non-operated interest in our E&P segment's Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. We received net proceeds of $1.3 billion and recorded a pretax gain on the sale of $811 million. We retained a 10 percent non-operated interest in Block 32.

Gudrun – In March 2011, we closed the sale of our non-operated interests in the Gudrun field development and the Brynhild and Eirin exploration areas offshore Norway for net proceeds of $85 million, excluding working capital adjustments. A $64 million pretax loss on this disposition was recorded in the fourth quarter 2010.

7. Income per Common Share

Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive.

	2012		2011		2010	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,582	$ 1,582	$ 1,707	$ 1,707	$ 1,882	$ 1,882
Discontinued operations	—	—	1,239	1,239	686	686
Net income	$ 1,582	$ 1,582	$ 2,946	$ 2,946	$ 2,568	$ 2,568
Weighted average common shares outstanding	706	706	710	710	710	710
Effect of dilutive securities	—	4	—	4	—	2
Weighted average common shares, including dilutive effect	706	710	710	714	710	712
Per share:						
Income from continuing operations	$ 2.24	$ 2.23	$ 2.40	$ 2.39	$ 2.65	$ 2.65
Discontinued operations	$ —	$ —	$ 1.75	$ 1.74	$ 0.97	$ 0.96
Net income	$ 2.24	$ 2.23	$ 4.15	$ 4.13	$ 3.62	$ 3.61

The per share calculations above exclude 10 million, 7 million and 13 million stock options and stock appreciation rights in 2012, 2011 and 2010 that were antidilutive.

8. Segment Information

We have three reportable operating segments. Each of these segments is organized and managed based upon the nature of the products and services they offer.

- E&P – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- OSM – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.
- IG – produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations, net of income taxes, attributable to the operating segments. Our corporate general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities, net of associated income tax effects. Impairments, gains or losses on disposal of assets, unrealized gains or losses on crude oil derivative instruments or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

As discussed in Note 3, our downstream business was spun-off on June 30, 2011 and has been reported as discontinued operations for 2011 and 2010. Sales to MPC previously reported as Intersegment revenues are reported as Customer revenues because such sales are expected to continue subsequent to the spin-off. Such sales were $1.4 billion in the first six months of 2011, and $1.8 billion in 2010.

Differences between segment totals and our consolidated totals for income taxes and depreciation, depletion and amortization represent amounts related to corporate administrative activities and other unallocated items which are included in "Items not allocated to segments, net of taxes" in the reconciliation below. Capital expenditures include accruals but not corporate administrative activities.

(In millions)	E&P	OSM	IG	Total
2012				
Revenues:				
Customer	$ 14,026	$ 1,552	$ —	$ 15,578
Related parties	58	—	—	58
Segment revenues	$ 14,084	$ 1,552	$ —	15,636
Unrealized gain on crude oil derivative instruments				52
Total revenues				$ 15,688
Segment income	$ 1,881	$ 176	$ 91	$ 2,148
Income from equity method investments	238	—	132	370
Depreciation, depletion and amortization	2,226	217	—	2,443
Income tax provision	4,741	59	27	4,827
Capital expenditures	4,835	188	2	5,025

(In millions)	E&P	OSM	IG	Total
2011				
Revenues:				
Customer	$ 12,922	$ 1,588	$ 93	$ 14,603
Intersegment	47	—	—	47
Related parties	60	—	—	60
Segment revenues	$ 13,029	$ 1,588	$ 93	14,710
Elimination of intersegment revenues				(47)
Total revenues				$ 14,663
Segment income	$ 2,157	$ 256	$ 178	$ 2,591
Income from equity method investments	249	—	213	462
Depreciation, depletion and amortization	2,028	196	3	2,227
Income tax provision	2,808	82	74	2,964
Capital expenditures	3,038	308	2	3,348

(In millions)	E&P	OSM	IG	Total
2010				
Revenues:				
Customer	$ 10,651	$ 833	$ 150	$ 11,634
Intersegment	75	—	—	75
Related parties	56	—	—	56
Segment revenues	$ 10,782	$ 833	$ 150	11,765
Elimination of intersegment revenues				(75)
Total revenues				$ 11,690
Segment income (loss)	$ 1,941	$ (50)	$ 142	$ 2,033
Income from equity method investments	188	—	181	369

Depreciation, depletion and amortization	1,911	105	2	2,018
Income tax provision (benefit)	2,266	(12)	73	2,327
Capital expenditures	2,474	874	2	3,350

The following reconciles total revenues to sales and other operating revenues in the consolidated statements of income.

(In millions)	2012	2011	2010
Total revenues	$ 15,688	$ 14,663	$ 11,690
Less: Sales to related parties	58	60	56
Sales and other operating revenues	$ 15,630	$ 14,603	$ 11,634

The following reconciles segment income to net income as reported in the consolidated statements of income.

(In millions)	2012	2011	2010
Segment income	$ 2,148	$ 2,591	$ 2,033
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(441)	(317)	(170)
Impairments	(231)	(195)	(286)
Gain on dispositions	72	45	407
Unrealized gain on crude oil derivative instruments	34	—	—
Loss on early extinguishment of debt	—	(176)	(57)
Tax effect of subsidiary restructuring	—	(122)	—
Deferred income tax items	—	(61)	(45)
Water abatement - Oil Sands	—	(48)	—
Eagle Ford transaction costs	—	(10)	—
Income from continuing operations	1,582	1,707	1,882
Discontinued operations	—	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568

Revenues from external customers are attributed to geographic areas based upon selling location. The following summarizes revenues from external customers by geographic area.

(In millions)	2012	2011	2010
United States	$ 6,442	$ 6,971	$ 5,363
United Kingdom	1,245	1,546	1,063
Libya[(a)]	1,989	216	1,473
Norway	3,582	3,386	2,243
Canada	1,552	1,588	833
Other international	878	956	715
Total revenues	$ 15,688	$ 14,663	$ 11,690

(a) See Note 13 for discussion of Libya operations.

In 2012, Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 15 percent of our total revenues, while sales to Shell Oil and its affiliates accounted for approximately 12 percent of total revenues. In 2011 and 2010, our sales to MPC accounted for approximately 18 percent and 16 percent of total revenues. In 2010, sales to the Libyan National Oil Company accounted for approximately 13 percent of total revenues.

Revenues by product line were:

(In millions)	2012	2011	2010
Liquid hydrocarbons	$ 12,945	$ 11,717	$ 9,480
Natural gas	1,103	1,291	1,295
Synthetic crude oil	1,545	1,581	832
Transportation & other	95	74	83
Total revenues	$ 15,688	$ 14,663	$ 11,690

The following summarizes certain long-lived assets by geographic area, including property, plant and equipment and equity investments.

(In millions)	2012	2011
United States	$ 13,677	$ 10,928
Canada	9,693	9,711
Equatorial Guinea	2,081	2,214
Norway	987	1,133
Other international	3,113	2,721
Total long-lived assets	$ 29,551	$ 26,707

9. Other Items

Net interest and other

(In millions)	2012	2011	2010
Interest:			
Interest income	$ 13	$ 12	$ 11
Interest expense[(a)]	(300)	(281)	(375)
Income on interest rate swaps	7	10	26
Interest capitalized	68	151	297
Total interest	(212)	(108)	(41)
Other:			
Net foreign currency gains (losses)	4	24	(21)
Write off of contingent proceeds	—	(7)	(15)
Other	(11)	(16)	2
Total other	(7)	1	(34)
Net interest and other	$ (219)	$ (107)	$ (75)

[(a)] Excludes $1 million, $10 million and $16 million paid by United States Steel in 2012, 2011 and 2010 on assumed debt.

Foreign currency transactions – Aggregate foreign currency gains (losses) were included in the consolidated statements of income as follows:

(In millions)	2012	2011	2010
Net interest and other	$ 4	$ 24	$ (21)
Provision for income taxes	80	(57)	(1)
Aggregate foreign currency gains (losses)	$ 84	$ (33)	$ (22)

10. Income Taxes

Income tax provisions (benefits) were:

	2012			2011			2010		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ (80)	$ 233	$ 153	$ (210)	$ (206)	$ (416)	$ (279)	$ (267)	$ (546)
State and local	(23)	47	24	24	82	106	2	(10)	(8)
Foreign	4,844	(490)	4,354	3,088	(58)	3,030	2,941	(212)	2,729
Total	$ 4,741	$ (210)	$ 4,531	$ 2,902	$ (182)	$ 2,720	$ 2,664	$ (489)	$ 2,175

A reconciliation of the federal statutory income tax rate applied to income from continuing operations before income taxes to the provision for income taxes follows:

	2012	2011	2010
Statutory rate applied to income from continuing operations before income taxes	35%	35%	35 %
Effects of foreign operations, including foreign tax credits	18	6	20
Change in permanent reinvestment assertion	—	5	—
Adjustments to valuation allowances	21	14	(2)
Tax law changes	—	1	1
Effective income tax rate on continuing operations	74%	61%	54 %

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in "Corporate and other unallocated items" shown in Note 8.

Effects of foreign operations – The effects of foreign operations on our effective tax rate increased in 2012 as compared to 2011, primarily due to the resumption of sales of Libyan production in 2012, where the statutory tax rate is in excess of 90 percent.

Change in permanent reinvestment assertion – In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognizing deferred U.S. tax on previously undistributed earnings.

Adjustments to valuation allowances – In 2012 and 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in those years.

Tax law changes – On July 17, 2012, the U.K. enacted Finance Bill 2012 which restricted relief on decommissioning charges and reduced the main corporate tax rate. There were no changes to the rate of corporation tax or the supplementary corporation tax for U.K. ring-fenced activities in the oil and gas sector. This legislation did not have a material impact on our consolidated financial statements. In July 2011, the U.K. enacted Finance Bill 2011 which increased the rate of the supplementary charge levied on profits from U.K. oil and gas production from 20 percent to 32 percent. As a result of this legislation, we recorded deferred tax expense of $10 million in 2011.

On May 25, 2011, Michigan enacted legislation that replaced the Michigan Business Tax ("MBT") with a corporate income tax ("CIT"), effective January 1, 2012. The CIT legislation eliminated the "book-tax difference deduction" that was provided under the MBT to mitigate the net increase in a taxpayer's deferred tax liability resulting when Michigan moved from the Single Business Tax, a non-income tax, to the MBT, an income tax, on July 12, 2007. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relates to discontinued operations. As a result of the new CIT legislation, we recorded deferred tax expense of $32 million in the second quarter of 2011.

The Patient Protection and Affordable Care Act ("PPACA") and the Health Care and Education Reconciliation Act of 2010 ("HCERA"), (together, the "Acts") were signed in to law in March 2010. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D. The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the "MPDIMA"). Under the MPDIMA, the federal subsidy did not reduce our income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually. Beginning in 2013, under the Acts, our income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relates to discontinued operations. As a result, we recorded deferred tax expense of $45 million in the first quarter of 2010 for the write-off of deferred tax assets to reflect the change in the tax treatment of the federal subsidy.

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(In millions)	2012	2011[(a)]
Deferred tax assets:		
Employee benefits	$ 510	$ 455
Operating loss carryforwards	368	354
Foreign tax credits	4,351	3,005
Other	121	95
Valuation allowances:		
Federal	(2,067)	(790)
State, net of federal benefit	(60)	(40)
Foreign	(210)	(194)
Total deferred tax assets	3,013	2,885
Deferred tax liabilities:		
Property, plant and equipment	3,691	3,404
Investments in subsidiaries and affiliates	840	1,216
Other	12	41
Total deferred tax liabilities	4,543	4,661
Net deferred tax liabilities	$ 1,530	$ 1,776

(a) Certain 2011 amounts were reclassified to conform to the current period's presentation.

Operating loss carryforwards – At December 31, 2012, our operating loss carryforwards include $811 million of Canadian operating loss carryforwards that expire from 2013 through 2032 and $216 million of Indonesian operating loss carryforwards that do not have expiration dates. State operating loss carryforwards of $1,363 million expire in 2013 through 2031.

Valuation allowances – The ability to realize the benefit of foreign tax credits is based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the years that such credits may be claimed. Federal valuation allowances increased $1,277 million in 2012, increased $585 million in 2011, and decreased $74 million in 2010 due to changes in the expected realizability of foreign tax credits.

Foreign valuation allowances increased $16 million in 2012, primarily due to deferred tax assets generated in the Kurdistan Region of Iraq and Angola. Foreign valuation allowances increased $52 million and $40 million in 2011 and 2010, primarily due to net operating loss carryforwards generated in Indonesia.

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(In millions)	2012	2011
Assets:		
Other current assets	$ 57	$ 99
Other noncurrent assets	849	674
Liabilities:		
Other current liabilities	4	5
Noncurrent deferred tax liabilities	2,432	2,544
Net deferred tax liabilities	$ 1,530	$ 1,776

We are continuously undergoing examination of our U.S. federal income tax returns by the IRS. Such audits have been completed through the 2009 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities.

As of December 31, 2012, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[(a)]	2005-2011
Canada	2008-2011
Equatorial Guinea	2007-2011
Libya	2006-2011
Norway	2008-2011
United Kingdom	2008-2011

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2012	2011	2010
Beginning balance	$ 157	$ 103	$ 75
Additions for tax positions related to the current year	—	4	28
Reductions for tax positions related to the current year	—	—	(1)
Additions for tax positions of prior years	81	87	25
Reductions for tax positions of prior years	(67)	(29)	(12)
Settlements	(72)	(8)	(12)
Statute of limitations	(1)	—	—
Ending balance	$ 98	$ 157	$ 103

If the unrecognized tax benefits as of December 31, 2012 were recognized, $92 million would affect our effective income tax rate. There were $16 million of uncertain tax positions as of December 31, 2012 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly increase or decrease during the next twelve months.

Interest and penalties are recorded as part of the tax provision and were $4 million, $13 million and $5 million related to unrecognized tax benefits in 2012, 2011 and 2010. As of December 31, 2012 and 2011, $24 million and $27 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $6,365 million, $4,869 million and $4,563 million in 2012, 2011 and 2010.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2012 amounted to $571 million for which no U.S. deferred income tax provision has been recorded because we intend to permanently reinvest such income in our foreign operations. If such income was not permanently reinvested, income tax expense of approximately $200 million would be recorded, not including potential utilization of foreign tax credits.

11. Inventories

Inventories are carried at the lower of cost or market value. The LIFO method accounted for 6 percent and 23 percent of total inventory value at December 31, 2012 and 2011. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2012 and 2011 by $29 million and $74 million.

	December 31,	
(In millions)	2012	2011
Liquid hydrocarbons, natural gas and bitumen	$ 73	$ 147
Supplies and sundry items	288	214
Inventories at cost	$ 361	$ 361

12. Equity Method Investments and Related Party Transactions

During 2012, 2011 and 2010 only our equity method investees were considered related parties and they included:

- Alba Plant LLC, in which we have a 52 percent noncontrolling interest. Alba Plant LLC processes LPG.
- AMPCO, in which we have a 45 percent interest. AMPCO is engaged in methanol production activity.
- EGHoldings, in which we have a 60 percent noncontrolling interest. EGHoldings is engaged in LNG production activities.

Our equity method investments are summarized in the following table:

		December 31,	
(In millions)	Ownership as of December 31, 2012	2012	2011
EGHoldings	60%	$ 817	$ 875
Alba Plant LLC	52%	264	272
AMPCO	45%	187	191
Other investments		11	45
Total		$ 1,279	$ 1,383

As of December 31, 2012, the carrying value of our equity method investments was $133 million higher than the underlying net assets of investees. This basis difference is being amortized into net income over the remaining estimated useful lives of the underlying net assets.

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $381 million in 2012, $509 million in 2011 and $400 million in 2010.

Summarized financial information for equity method investees is as follows:

(In millions)	2012	2011	2010
Income data – year:			
Revenues and other income	$ 1,330	$ 1,544	$ 1,305
Income from operations	755	942	762
Net income	635	820	671
Balance sheet data – December 31:			
Current assets	$ 607	$ 688	
Noncurrent assets	1,743	2,079	
Current liabilities	395	504	

Noncurrent liabilities	29	115

Almost all of our purchases from related parties are liquid hydrocarbons acquired from Alba Plant LLC. Approximately 75 percent of our sales to related parties in all periods are associated with sales of natural gas to EGHoldings.

13. Property, Plant and Equipment

(In millions)	December 31, 2012	2011
E&P		
United States	$ 23,400	$ 19,679
International	13,523	12,579
Total E&P	36,923	32,258
OSM	10,128	9,936
IG	38	37
Corporate	449	341
Total property, plant and equipment	$ 47,538	$ 42,572
Less accumulated depreciation, depletion and amortization	(19,266)	(17,248)
Net property, plant and equipment	$ 28,272	$ 25,324

In the first quarter of 2011, production operations in Libya were suspended. In the fourth quarter of 2011, limited production resumed. Since that time, average net liquid hydrocarbon sales volumes have increased to pre-conflict levels. We and our partners in the Waha concessions continue to assess the condition of our assets in Libya and uncertainty around sustained production and sales levels remains. As of December 31, 2012, our net property, plant and equipment investment in Libya is approximately $745 million and total proved reserves in Libya are 244 mmboe.

Deferred exploratory well costs were as follows:

(In millions)	December 31, 2012	2011	2010
Amounts capitalized less than one year after completion of drilling	$ 388	$ 482	$ 334
Amounts capitalized greater than one year after completion of drilling	229	222	323
Total deferred exploratory well costs	$ 617	$ 704	$ 657
Number of projects with costs capitalized greater than one year after completion of drilling	6	5	7

(In millions)	2012	2011	2010
Beginning balance	$ 704	$ 657	$ 829
Additions	731	670	329
Dry well expense	(143)	(268)	(83)
Transfers to development	(629)	(279)	(54)
Dispositions	(46)	(76)	(364)
Ending balance	$ 617	$ 704	$ 657

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2012 are summarized by geographical area below:

(In millions)	
Angola	$ 128
Norway	70
E.G.	22
U.S.	9
Total	$ 229

Well costs that have been suspended for longer than one year are associated with 6 projects. Management believes these projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development.

Angola – Exploration on Angola Block 31 began in 2004, with costs accumulating through 2009. Development alternatives are being evaluated and optimization efforts continue for this block.

Norway – Three offshore Norway development projects had costs incurred from 2009 through 2011. The development plan for Boyla was approved by the Norwegian government in October 2012. This will tie-back to the Alvheim FPSO and development drilling is expected to begin in late 2013. Development options are being evaluated for Caterpillar and drilling on Viper is planned for 2015.

E.G. – The Corona well on Block D offshore E.G. was drilled in 2004, and we acquired an additional interest in the well in 2012. We plan to develop Block D through a unitization with the Alba field, which is expected in late 2013 or early 2014.

U.S. – We incurred drilling costs in the Marcellus natural gas shale play from 2009 through 2010, and were carried in drilling that occurred during 2011. At the end of 2012, our plans were to hold and develop our leasehold position in 2013 by drilling and completing one new well and completing one previously drilled well. In February 2013, we entered an agreement to convey our interest in this asset to the operator.

14. Goodwill

Goodwill is tested for impairment on an annual basis, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill has been reduced below the carrying value. We performed our annual impairment tests during 2012, 2011 and 2010 and no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value appreciably; however, should market conditions deteriorate or commodity prices decline significantly, an impairment may be necessary.

The changes in the carrying amount of goodwill for the years ended December 31, 2012 and 2011 were as follows:

(In millions)	E&P	OSM	Downstream business	Total
2011				
Beginning balance, gross	$ 537	$ 1,412	$ 843	$ 2,792
Less: accumulated impairment	—	(1,412)	—	(1,412)
Beginning balance, net	537	—	843	1,380
Contingent consideration adjustment	—	—	(3)	(3)
Purchase price adjustment	—	—	9	9
Dispositions	(1)	—	(2)	(3)
Spin-off downstream business	—	—	(847)	(847)
Ending balance, net	536	—	—	536
2012				

Beginning balance, gross	536	1,412	—	1,948
Less: accumulated impairments	—	(1,412)	—	(1,412)
Beginning balance, net	536	—	—	536
Dispositions	(11)	—	—	(11)
Ending balance, net	$ 525	$ —	$ —	$ 525

15. Fair Value Measurements

Fair values – Recurring

The following table presents assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2012 by fair value hierarchy level.

	December 31, 2012				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ —	$ 52	$ —	$ 1	$ 53
Interest rate	—	21	—	—	21
Foreign currency	—	18	—	—	18
Derivative instruments, assets	$ —	$ 91	$ —	$ 1	$ 92

As of December 31, 2011, balances related to interest rate swaps accounted for at fair value on a recurring basis were noncurrent assets of $5 million measured at fair value using actionable broker quotes which are Level 2 inputs. There were no other significant recurring fair value measurements as of December 31, 2011.

Commodity swaps in Level 2 are measured at fair value with a market approach using prices obtained from exchanges or pricing services, which have been corroborated with data from active markets for similar assets or liabilities. Commodity options in Level 2 are valued using the Black-Scholes Model. Inputs to this model include prices as noted above, discount factors, and implied market volatility. The inputs to this fair value measurement are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments. Collateral deposits related to commodity derivatives are in broker accounts covered by master netting agreements.

Interest rate swaps are measured at fair value with a market approach using actionable broker quotes which are Level 2 inputs. Foreign currency forwards are measured at fair value with a market approach using third-party pricing services, such as Bloomberg L.P., which have been corroborated with data from active markets for similar assets or liabilities, and are Level 2 inputs.

Fair values – Nonrecurring

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	2012		2011		2010	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 16	$ 371	$ 226	$ 285	$ 147	$ 447
Long-lived assets held for sale	—	—	—	—	85	64
Intangible assets	—	—	—	25	—	—
Equity method investments	—	—	—	—	—	25

Long-lived assets held for use – All long-lived assets held for use that were impaired in 2012, 2011 and 2010 were held by our E&P segment. The fair values of each discussed below were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement included reserve and production estimates made by our reservoir engineers, estimated commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

During early 2012, production rates from the Ozona development in the Gulf of Mexico declined significantly and have remained below initial expectations. Accordingly, our reserve engineers performed evaluations of our future production as well as our reserves and an impairment was recorded in the first quarter of 2012. As the development produced toward abandonment pressures, further downward revisions of reserves were taken, resulting in a fair value measurement of $6 million by year end for an aggregate impairment of $289 million in 2012.

In the fourth quarter of 2012, declining natural gas prices prompted lower production expectations and reductions in estimated reserves related to our Powder River Basin asset. This resulted in an impairment of $73 million to reach the $6 million fair value of this asset. Additionally, in March 2010, we completed a reservoir study which resulted in a portion of our Powder River Basin asset being removed from plans for future development. At that time, the asset's fair value was measured at $144 million and an impairment of $423 million was recorded.

In May 2011, significant water production and reservoir pressure declines occurred at our Droshky development in the Gulf of Mexico. Plans for a waterflood were canceled and the field will be produced to abandonment pressures, which are expected in the first half of 2013. Consequently, proved reserves were reduced by 3.4 million boe and a $273 million impairment of this asset to its $226 million fair value was recorded in 2011.

Other impairments of long-lived assets held for use by our E&P segment in 2012, 2011 and 2010 were a result of reduced drilling expectations, reductions of estimated reserves or declining natural gas prices.

Intangible assets – In the second quarter of 2011, our outlook for U.S. natural gas prices made it unlikely that sufficient U.S. demand for LNG would materialize by 2021, which is when the rights lapse under our arrangements at the Elba Island, Georgia regasification facility. Using an income approach based upon internal estimates of gas prices and future deliveries, which are Level 3 inputs, we determined that the contract had no remaining fair value and recorded a full impairment of this intangible asset held in our IG segment.

Long-lived assets held for sale – In the fourth quarter of 2010, due to the pending sale of our E&P segment's non-operated interest in the Gudrun field development, located offshore Norway, we recorded a loss for this asset held for sale. The fair value was based upon the transaction, which is a Level 3 market input.

Equity method investments – In the third quarter of 2010, we fully impaired our IG segment's equity method investment in an entity engaged in gas-to-fuels related technology. This investment was determined to have sustained an other than temporary loss in value. The fair value was measured with an income approach using internally developed estimates of future cash flows. These cash flows are Level 3 inputs.

Fair values – Financial instruments

Our current assets and liabilities include financial instruments, the most significant of which are accounts receivables, commercial paper and payables. We believe the carrying values of accounts receivable, commercial paper and payables approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding trade accounts receivable, commercial paper, payables and derivative financial instruments and their reported fair value, by individual balance sheet line item at December 31, 2012 and 2011.

	December 31,			
	2012		2011	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 2	$ 2	$ 146	$ 148
Other noncurrent assets	189	186	68	68
Total financial assets	191	188	214	216
Financial liabilities				
Other current liabilities	13	13	—	—
Long-term debt, including current portion[(a)]	7,610	6,642	5,479	4,753
Deferred credits and other liabilities	94	94	36	38
Total financial liabilities	$ 7,717	$ 6,749	$ 5,515	$ 4,791

[(a)] Excludes capital leases.

Fair values of our remaining financial assets included in other current assets and other noncurrent assets, and of our financial liabilities included in other current liabilities and deferred credits and other liabilities are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

Most of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions, is used to measure the fair value of such debt. Because these quotes cannot be independently verified to an active market they are considered Level 3 inputs. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

16. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 15. See Note 1 for discussion of the types of derivatives we use and the reasons for them. The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheet as of December 31, 2012.

	December 31, 2012			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$ 18	$ —	$ 18	Other current assets
Interest rate	21	—	21	Other noncurrent assets
Total Designated Hedges	39	—	39	
Not Designated as Hedges				
Commodity	52	—	52	Other current assets
Total Not Designated as Hedges	52	—	52	
Total	$ 91	$ —	$ 91	

As of December 31, 2011, our only derivatives outstanding were interest rate swaps that are fair value hedges, which had an asset value of $5 million and were located on the consolidated balance sheet in other noncurrent assets.

Derivatives Designated as Fair Value Hedges

As of December 31, 2012 and 2011, we had multiple interest rate swap agreements with a total notional amount of $600 million with a maturity date of October 1, 2017 at a weighted-average, LIBOR-based, floating rate of 4.70 percent and 4.76 percent, respectively.

In connection with the debt retired in February and March 2011 discussed in Note 17, we settled interest rate swaps with a notional amount of $1,450 million. We recorded a $29 million gain, which reduced the loss on early extinguishment of debt.

As of December 31, 2012, our foreign currency forwards had an aggregate notional amount of 3,043 million Norwegian Kroner at a weighted average forward rate of 5.780. These forwards hedge our current Norwegian tax liability and have settlement dates through June 2013.

The following table summarizes the pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income.

		Gain (Loss)		
(In millions)	Income Statement Location	2012	2011	2010
Derivative				
Commodity	Sales and other operating revenues	$ —	$ —	$ (1)
Interest rate	Net interest and other	16	28	26
Interest rate	Loss on early extinguishment of debt	—	29	—
Foreign currency	Provision for income taxes	(1)	—	—
Hedged Item				
Commodity	Sales and other operating revenues	$ —	$ —	$ 1
Long-term debt	Net interest and other	(16)	(28)	(26)
Long-term debt	Loss on early extinguishment of debt	—	(29)	—
Accrued taxes	Provision for income taxes	1	—	—

Derivatives Not Designated as Hedges

In August 2012, we entered into crude oil derivatives related to a portion of our forecasted U.S. E&P crude oil sales through December 31, 2013. These commodity derivatives were not designated as hedges and are shown in the table below.

Remaining Term	Bbls per Day	Weighted Average Price per Bbl	Benchmark
Swaps			
January 2013 - December 2013	20,000	$96.29	West Texas Intermediate
January 2013 - December 2013	25,000	$109.19	Brent
Option Collars			
January 2013 - December 2013	15,000	$90.00 floor / $101.17 ceiling	West Texas Intermediate
January 2013 - December 2013	15,000	$100.00 floor / $116.30 ceiling	Brent

The net gains related to all commodity derivative instruments not designated as hedges appear in the sales and other operating revenues line of our consolidated statements of income and were $70 million, $5 million and $121 million in 2012, 2011 and 2010.

17. Debt

Short-term debt

As of December 31, 2012, we had no borrowings against our revolving credit facility, as described below, and we had $200 million in commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

In April 2012, we terminated our $3.0 billion five-year revolving credit facility and replaced it with a new $2.5 billion unsecured five-year revolving credit facility (the "Credit Facility"). The Credit Facility matures in April 2017, but allows us to request two one-year extensions. It contains an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and includes sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million, respectively. Fees on the unused commitment of each lender range from 10 basis points to 25 basis points depending on our credit ratings. Borrowings under the Credit Facility bear interest, at our option, at either (a) an adjusted LIBOR rate plus a margin ranging from 87.5 basis points to 162.5 basis points per year depending on our credit ratings or (b) the Base Rate plus a margin ranging from 0.0 basis points to 62.5 basis points depending on our credit ratings. Base Rate is defined as a per annum rate equal to the greatest of (a) the prime rate, (b) the federal funds rate plus one-half of one percent and (c) LIBOR for a one-month interest period plus one percent.

The agreement contains a covenant that requires our ratio of total debt to total capitalization not to exceed 65 percent as of the last day of each fiscal quarter. If an event of default occurs, the lenders may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility.

Long-term debt

The following table details our long-term debt:

(In millions)	December 31, 2012	December 31, 2011
Senior unsecured notes:		
9.375% notes due 2012	$ —	$ 53
9.125% notes due 2013	114	114
0.900% notes due 2015[a]	1,000	—
6.000% notes due 2017[a]	682	682
5.900% notes due 2018[a]	854	854
7.500% notes due 2019[a]	228	228
2.800% notes due 2022[a]	1,000	—
9.375% notes due 2022	32	32
Series A notes due 2022	3	3
8.500% notes due 2023	70	70
8.125% notes due 2023	131	131
6.800% notes due 2032[a]	550	550
6.600% notes due 2037	750	750
Capital leases:		
Capital lease obligation due 2012	—	9
Sale-leaseback obligation due 2012	—	11
Capital lease obligation of consolidated subsidiary due 2013 – 2049	11	11
Other obligations:		
4.550% promissory note, semi-annual payments due 2013 – 2015	204	272
5.375% obligation relating to revenue bonds due 2013	—	23
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Other	35	—
Total[b]	6,664	4,793
Unamortized discount	(11)	(10)
Fair value adjustments[c]	43	32
Amounts due within one year	(184)	(141)
Total long-term debt due after one year	$ 6,512	$ 4,674

[a] These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

[b] In the event of a change in control, as defined in the related agreements, debt obligations totaling $385 million at December 31, 2012, may be declared immediately due and payable.

[c] See Note 15 for information on interest rate swaps.

On October 29, 2012, we issued $1 billion aggregate principal amount of senior notes bearing interest at 0.9 percent with a maturity date of November 1, 2015 and $1 billion aggregate principal amount of senior notes bearing interest at 2.8 percent with a maturity date of November 1, 2022. Interest on the senior notes is payable semi-annually beginning May 1, 2013. The proceeds were used to pay off commercial paper and for general corporate purposes.

In the second quarter of 2012, we retired the remaining $23 million principal amount of our 5.375 percent revenue bonds due December 2013. No gain or loss was recorded on this early extinguishment of debt.

In February and March 2011, we retired $2,498 million aggregate face amount of debt at a weighted average price equal to 112 percent of face value. A $279 million loss on early extinguishment of debt was recognized in the first quarter of 2011. The loss includes related deferred financing and premium costs partially offset by the gain on settled interest rate swaps.

The following table shows five years of long-term debt payments:

(In millions)		
2013	$	184
2014		71
2015		1,070
2016		3
2017		685

18. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)		2012		2011
Beginning balance	$	1,510	$	1,355
Incurred, including acquisitions		150		37
Settled, including dispositions		(35)		(39)
Accretion expense (included in depreciation, depletion and amortization)		91		81
Revisions to previous estimates		150		126
Held for sale		(83)		—
Spin-off downstream business		—		(50)
Ending balance[(a)]	$	1,783	$	1,510

[(a)] Includes asset retirement obligations of $34 million classified as a short-term at December 31, 2012.

19. Supplemental Cash Flow Information

(In millions)		2012		2011		2010
Net cash provided by operating activities included:						
Interest paid (net of amounts capitalized)	$	225	$	268	$	107
Income taxes paid to taxing authorities		4,974		2,893		2,155
Commercial paper:						
Issuances	$	13,880	$	421	$	—
Repayments		(13,680)		(421)		—
Net commercial paper	$	200	$	—	$	—
Noncash investing and financing activities:						
Additions to property, plant and equipment						
Asset retirement costs capitalized, excluding acquisitions	$	286	$	151	$	207
Change in capital expenditure accrual		191		104		(140)
Liabilities assumed in acquisitions		109		126		—
Debt payments made by United States Steel		20		214		105

20. Defined Benefit Postretirement Plans and Defined Contribution Plan

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Norway and the U.K. Benefits under these plans are based on plan provisions specific to each plan.

We also have defined benefit plans for other postretirement benefits covering our U.S. employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Life insurance benefits are provided to certain retiree beneficiaries. Other postretirement benefits are not funded in advance.

Obligations and funded status – The accumulated benefit obligation for all defined benefit pension plans was $1,442 million and $1,231 million as of December 31, 2012 and 2011.

As of December 31, 2012 and 2011, our U.S. plans and our international plans all have accumulated benefit obligations in excess of plan assets. Summary information for our defined benefit pension plans follows.

	December 31,			
	2012		2011	
(In millions)	U.S.	Int'l	U.S.	Int'l
Projected benefit obligation	$ (1,146)	$ (565)	$ (986)	$ (465)
Accumulated benefit obligation	(937)	(505)	(813)	(418)
Fair value of plan assets	630	500	516	412

The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2012		2011		2012	2011
(In millions)	U.S.	Int'l	U.S.	Int'l		
Change in benefit obligations:						
Benefit obligations at January 1	$ 986	$ 465	$ 3,221	$ 415	$ 301	$ 779
Spin-off downstream business	—	—	(2,308)	—	—	(483)
Service cost	31	19	28	19	4	4
Interest cost	42	22	44	22	14	16
Plan amendment	—	—	—	11	—	—
Actuarial loss	196	49	84	13	8	1
Foreign currency exchange rate changes	—	25	—	(2)	—	—
Benefits paid	(109)	(15)	(83)	(13)	(16)	(16)
Benefit obligations at December 31	$ 1,146	$ 565	$ 986	$ 465	$ 311	$ 301
Change in plan assets:						
Fair value of plan assets at January 1	$ 516	$ 412	$ 1,798	$ 389	$ —	$ —
Spin-off downstream business	—	—	(1,268)	—	—	—
Actual return on plan assets	66	57	30	15	—	—
Employer contributions	157	24	39	23	—	—
Foreign currency exchange rate changes	—	22	—	(2)	—	—
Benefits paid	(109)	(15)	(83)	(13)	—	—
Fair value of plan assets at December 31	$ 630	$ 500	$ 516	$ 412	$ —	$ —
Funded status of plans at December 31	$ (516)	$ (65)	$ (470)	$ (53)	$ (311)	$ (301)
Amounts recognized in the consolidated balance sheet:						
Current liabilities	(17)	—	(17)	—	(19)	(18)
Noncurrent liabilities	(499)	(65)	(453)	(53)	(292)	(283)
Accrued benefit cost	$ (516)	$ (65)	$ (470)	$ (53)	$ (311)	$ (301)
Pretax amounts in accumulated other comprehensive loss:						
Net loss	$ 511	$ 74	$ 432	$ 63	$ 23	$ 16
Prior service cost (credit)	21	10	27	11	(11)	(18)

Components of net periodic benefit cost and other comprehensive (income) loss – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive (income) loss for our defined benefit pension and other postretirement plans.

	Pension Benefits								
	2012		2011		2010		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2012	2011	2010
Components of net periodic benefit cost:									
Service cost	$ 31	$ 19	$ 28	$ 19	$ 30	$ 19	$ 4	$ 4	$ 3
Interest cost	42	22	44	22	47	22	14	16	16
Expected return on plan assets	(43)	(22)	(43)	(23)	(44)	(22)	—	—	—
Amortization:									
- prior service cost (credit)	7	1	6	—	6	—	(7)	(7)	(7)
- actuarial loss	48	4	47	2	48	5	—	—	—
Other	—	—	—	—	—	2	—	—	—
Net settlement loss[a]	45	—	30	—	56	—	—	—	—
Net periodic benefit cost[b]	$ 130	$ 24	$ 112	$ 20	$ 143	$ 26	$ 11	$ 13	$ 12
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)	$ 172	$ 15	$ 97	$ 24	$ 211	$ (25)	$ 7	$ 1	$ 69
Amortization of actuarial (loss) gain	(93)	(4)	(77)	(2)	(167)	(5)	—	—	2
Prior service cost	—	1	—	(11)	—	—	—	—	—
Amortization of prior service credit (cost)	(7)	(1)	(6)	—	(13)	—	7	7	6
Spin-off downstream business [c]	—	—	(24)	—	—	—	—	—	—
Total recognized in other comprehensive (income) loss	$ 72	$ 11	$ (10)	$ 11	$ 31	$ (30)	$ 14	$ 8	$ 77
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 202	$ 35	$ 102	$ 31	$ 174	$ (4)	$ 25	$ 21	$ 89

[a] Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2012, 2011 and 2010.

[b] Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

[c] Includes net inter-company transfers of (gains)/losses due to the spin-off of the downstream business.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2013 are $52 million and $7 million. The estimated net loss and prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2013 are $1 million and $7 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2012, 2011 and 2010.

	Pension Benefits								
	2012		2011		2010		Other Benefits		
(In millions)	U.S.	Int’l	U.S.	Int’l	U.S.	Int’l	2012	2011	2010
Weighted average assumptions used to determine benefit obligation:									
Discount rate	3.44%	4.40%	4.45%	4.70%	5.05%	5.40%	4.06%	4.90%	5.55%
Rate of compensation increase	5.00%	4.50%	5.00%	4.30%	5.00%	5.10%	5.00%	5.00%	5.00%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	4.21%	4.70%	5.05%	5.40%	5.23%	5.70%	4.90%	5.55%	6.85%
Expected long-term return on plan assets	7.75% (a)	5.20%	8.50%	5.86%	8.50%	6.40%	—	—	—
Rate of compensation increase	5.00%	4.30%	5.00%	5.10%	4.50%	5.55%	5.00%	5.00%	4.50%

(a) Effective January 1, 2013, the expected long-term rate of return on plan assets was changed from 7.75 percent to 7.25 percent.

Expected long-term return on plan assets

U.S. plan – The overall expected long-term return on plan assets assumption for our U.S. plan is determined based on an asset rate-of-return modeling tool developed by a third-party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan’s asset allocation to derive an expected long-term rate of return on those assets. Capital market assumptions reflect the long-term capital market outlook. The assumptions for equity and fixed income investments are developed using a building-block approach, reflecting observable inflation information and interest rate information available in the fixed income markets. Long-term assumptions for other asset categories are based on historical results, current market characteristics and the professional judgment of our internal and external investment teams.

International plans – To determine the overall expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation in our international pension plans to develop the overall expected long-term return on plan assets assumption.

Assumed health care cost trend rates

	2012	2011	2010
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	8.00%	7.50%	7.50%
Post-65	7.00%	7.00%	7.00%
Prescription drugs	7.00%	7.50%	7.50%
EGWP subsidy[a]	7.50%	n/a	n/a
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	5.00%	5.00%
EGWP subsidy[a]	5.00%	n/a	n/a
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2020	2018	2018
Post-65	2018	2017	2017
Prescription drugs	2018	2018	2018
EGWP subsidy[a]	2020	n/a	n/a

[a] An employee group waiver plan ("EGWP") is a group Medicare Part D prescription drug plan. Effective January 1, 2013, we implemented the EGWP as a result of the Patient Protection and Affordable Care Act, which ended tax-free status of retiree drug subsidy programs but increased federal funding to Part D prescription drug plans.

Assumed health care cost trend rates have a significant effect on the amounts reported for defined benefit retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 2	$ (2)
Effect on other postretirement benefit obligations	$ 35	$ (29)

Plan investment policies and strategies

The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plan – Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments are utilized for pension payments, expenses, and other liquidity needs. As such, the plan's targeted asset allocation is comprised of 65 percent equity securities and high-yield bonds and 35 percent other fixed income securities but may be adjusted to better match the plan's liabilities over time as the funded ratio (as defined by the investment policy) changes.

The plan's assets are managed by a third-party investment manager. The investment manager is limited to pursuing the investment strategies regarding asset mix and purchases and sales of securities within the parameters defined in the investment policy guidelines and investment management agreement. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plans – Our international plans' target asset allocation is comprised of 70 percent equity securities and 30 percent fixed income securities. The plan assets are invested in eleven separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. Investments are diversified by industry and type, limited by grade and maturity. The use of derivatives by the investment managers is permitted, subject to strict guidelines. The investment managers' performance is measured independently by a third-party asset servicing consulting firm. Overall, investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Fair value measurements

Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2012 and 2011.

Cash and cash equivalents – Cash and cash equivalents include cash on deposit and an investment in a money market mutual fund that invests mainly in short-term instruments and cash, both of which are valued using a market approach and are considered Level 1. The money market mutual fund is valued at the net asset value ("NAV") of shares held. Cash and cash equivalents also include a cash reserve account (a collective short-term investment fund) that is valued using an income approach and is considered Level 2. The underlying assets are usually short-term bonds, discount notes, and commercial paper.

Equity securities – Investments in common stock, an S&P 500 exchange-traded fund, and real estate investment trusts ("REIT") are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. The non-public investment trust is valued using a market approach based on the underlying investments in the trust, which are publicly-traded securities, and is considered Level 2. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

Mutual funds – Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and such prices are Level 1 inputs.

Pooled funds – Investments in pooled funds are valued using a market approach at the NAV of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds are benchmarked against a relative public index. These are considered Level 2.

Fixed income securities – U.S. treasury notes and exchange traded funds are valued at the closing price reported in an active market, and are considered Level 1. Corporate bonds, non-U.S. government bonds, private placements, and yankee bonds are valued using calculated yield curves created by models that incorporate factors such as interest rate, benchmark quote, trade data, dealer quotes, primary and secondary market spread activity, and other market information and are considered Level 2. Taxable municipal bonds are valued using calculated yield curves considering market factors such as benchmark issues, trades, trading spreads between similar issuers or creditors, historical trading spreads over widely accepted market benchmarks, and verified bid information. These assets are considered Level 2. The investment in the commingled fund is valued using a market approach at the NAV of units held, and is considered Level 2. The commingled fund consists mostly of high yield U.S. and non-U.S. corporate bonds. Investment opportunities in this fund are limited to qualified retirement plans and their plan participants. The investment objective of the portfolio is to provide long-term total return in excess of the Barclays U.S. High Yield Bond Index.

Real estate – Real estate investments are valued based on discounted cash flows, comparable sales, outside appraisals, price per square foot or some combination thereof and therefore are considered Level 3.

Other – Other investments are composed of an investment in an unallocated annuity contract, an investment contract with an international insurance carrier, and investments in two limited liability companies ("LLCs") with no public market. The LLCs were formed to acquire timberland in the northwest and other properties. The investment in an unallocated annuity contract is valued using a market approach based on the experience of the assets held in an insurer's general account. The majority of the general account is invested in a well-diversified portfolio of high-quality fixed income securities, primarily consisting of investment-grade bonds. Investment income is allocated among pension plans participating in the general account based on the investment year method. Under this method, a record of the book value of assets held is maintained in subdivisions according to the calendar year in which the funds are invested. The earnings rate for each of these calendar year subdivisions varies from year to year, reflecting the actual earnings on the assets attributed to that year. Due to the lack of transparency in the use of investment year subdivisions, this asset is considered Level 3. The insurance carrier contract is funded by premiums paid annually by the participating plans and the funds are invested by the insurance carrier in portfolios with different risk profiles (low, medium, high) that can be elected by clients. The majority of the underlying investments consists of a well-diversified mix of non-U.S. publicly traded equity and fixed income securities. This asset is considered Level 2. The values of the LLCs are determined using a cost approach based on historical cost less depletion for timber previously harvested. These assets are considered Level 3.

The following table presents the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2012 and 2011.

	December 31, 2012							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 16	$ 1	$ 1	$ —	$ —	$ —	$ 17	$ 1
Equity securities:								
Common stock[a]	312	—	—	—	—	—	312	—
Private equity	—	—	—	—	25	—	25	—
REIT	2	—	—	—	—	—	2	—
Investment trust	—	—	1	—	—	—	1	—
Mutual funds[b]	—	171	—	—	—	—	—	171
Pooled funds[c]	—	—	—	152	—	—	—	152
Fixed income securities:								
U.S. treasury notes	67	—	—	—	—	—	67	—
Exchange traded fund	8	—	—	—	—	—	8	—
Corporate bonds[d]	—	—	96	—	—	—	96	—
Non-U.S. government bonds	—	—	5	—	—	—	5	—
Private placements	—	—	18	—	—	—	18	—
Taxable municipal bonds	—	—	14	—	—	—	14	—
Yankee bonds	—	—	2	—	—	—	2	—
Commingled fund[e]	—	—	28	—	—	—	28	—
Pooled funds[f]	—	—	—	166	—	—	—	166
Real estate[g]	—	—	—	—	23	—	23	—
Other	—	—	—	10	12	—	12	10
Total investments, at fair value	$ 405	$ 172	$ 165	$ 328	$ 60	$ —	$ 630	$ 500

	December 31, 2011							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 12	$ 2	$ —	$ —	$ —	$ —	$ 12	$ 2
Equity securities:								
Investment trust	—	—	7	—	—	—	7	—
Exchange traded fund	324	—	—	—	—	—	324	—
Private equity	—	—	—	—	23	—	23	—
Mutual funds[b]	—	159	—	—	—	—	—	159
Pooled funds[c]	—	—	—	96	—	—	—	96
Fixed income securities:								
Pooled funds[f]	—	—	—	149	—	—	—	149
U.S. treasury notes	92	—	—	—	—	—	92	—
Real estate[g]	—	—	—	—	21	—	21	—
Other[h]	—	—	23	6	14	—	37	6

Total investments, at fair value	$ 428	$ 161	$ 30	$ 251	$ 58	$ —	$ 516	$ 412

[a] Includes approximately 60 percent of U.S. and non-U.S. common stocks in the pharmaceuticals, banking, oil and gas, telecommunications, electric, retail, transportation, aerospace/defense, insurance, manufacturing, health care, computer, and financial services sectors. The remaining 40 percent of common stock is held in various other sectors.

[b] Includes approximately 75 percent of investments held in U.S. and non-U.S. common stocks in the financial services, consumer staples, health care, energy, basic materials, industrial goods and services, and leisure sectors and 25 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, FTSE ALL Share 5% Capped Index and MSCI World Index, as defined by the investment policy.

[c] Includes approximately 90 percent of investments held in non-U.S. publicly traded common stocks (specifically Asia Pacific, except Japan, and the U.K.) in the financial, energy, consumer staples, industrial, and materials sectors and the remaining 10 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, MSCI AC Asia Pacific ex Japan Index, FTSE Small Cap Index, and MSCI Emerging Markets Index, as defined by the investment policy.

[d] Includes approximately 70 percent of U.S. and non-U.S. corporate bonds in the banking and finance, news/media, oil and gas, utilities, and health care sectors. The remaining 30 percent of corporate bonds are in various other sectors.

[e] Includes approximately 75 percent of investments held in U.S. and non-U.S. corporate bonds in the consumer discretionary, energy, financial, industrial, telecommunication services, and health care sectors and 25 percent of investments held among various other sectors.

[f] Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financial, corporates, and collateralized asset backed securities and 20 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, as defined by the investment policy.

[g] Includes investments diversified by property type and location. The largest property sector holdings, which represent approximately 70 percent of investments held, are office, hotel, residential, and retail with the greatest percentage of investments made in the U.S. and Asia, which includes the emerging markets of China and India.

[h] U.S. Level 2 includes a receivable for the sale of an investment that closed as of December 31, 2011 but did not cash settle until the next business day.

The following is a reconciliation of the beginning and ending balances recorded for plan assets classified as Level 3 in the fair value hierarchy.

	2012			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 23	$ 21	$ 14	$ 58
Actual return on plan assets:				
Realized	2	—	—	2
Unrealized	1	1	(2)	—
Purchases	4	3	—	7
Sales	(5)	(2)	—	(7)
Ending balance	$ 25	$ 23	$ 12	$ 60

	2011			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 67	$ 54	$ 31	$ 152
Less spin-off of downstream business	(46)	(37)	(17)	(100)
Actual return on plan assets:				
Realized	1	1	—	2
Unrealized	2	1	—	3
Purchases	3	4	—	7
Sales	(4)	(2)	—	(6)
Ending balance	$ 23	$ 21	$ 14	$ 58

Cash flows

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $64 million in 2013. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $16 million and $18 million in 2013.

Estimated future benefit payments – The following gross benefit payments, which reflect expected future services, as appropriate, are expected to be paid in the years indicated.

	Pension Benefits		Other Benefits
(In millions)	U.S.	Int'l	
2013	$ 113	$ 12	$ 18
2014	114	14	19
2015	114	16	20
2016	112	18	20
2017	114	20	20
2018 through 2022	530	109	101

Contributions to defined contribution plan – We contribute to a defined contribution plan for eligible employees. Contributions to this plan totaled $25 million, $21 million and $20 million in 2012, 2011 and 2010.

21. Incentive Based Compensation

Description of stock based compensation plans

The Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan") was approved by our stockholders in April 2012 and authorizes the Compensation Committee of the Board of Directors to grant stock options, SARs, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2012 Plan also allows us to provide equity compensation to our non-employee directors. No more than 50 million shares of our common stock may be issued under the 2012 Plan. For stock options and SARs, the number of shares available for issuance under the 2012 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted. For awards other than stock options or SARs, the number of shares available for issuance under the 2012 Plan will be reduced by 2.41 shares for each share of our common stock in respect of which the award is granted.

Shares subject to awards under the 2012 Plan that are forfeited, are terminated or expire unexercised become available for future grants. If a SAR is settled upon exercise by delivery of shares of common stock, the full number of shares with respect to which the SAR was exercised will count against the number of shares of our common stock reserved for issuance under the 2012 Plan and will not again become available under the 2012 Plan. In addition, the number of shares of our common stock reserved for issuance under the 2012 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2012 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2012 Plan, no new grants were or will be made from the 2007 Incentive Compensation Plan (the "2007 Plan"), the 2003 Incentive Compensation Plan (the "2003 Plan"), the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (the "Prior Plans"). Any awards previously granted under the 2007 Plan, the 2003 Plan or the Prior Plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock based awards under the plans

Stock options – We grant stock options under the 2012 Plan and previously granted stock options under the 2007 Plan and the 2003 Plan. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. Through 2004, certain stock options were granted under the 2003 Plan with a tandem SAR, which allows the recipient to instead elect to receive cash or our common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the 2003 Plan, over the option price of the shares. In general, stock options granted under the 2012 Plan, the 2007 Plan and the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights – Prior to 2005, we granted SARs under the 2003 Plan. No SARs have been granted under the 2012 Plan or the 2007 Plan. Similar to stock options, SARs represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Under the 2003 Plan, certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs granted under the 2003 Plan vested ratably over a three-year period and have a maximum term of ten years from the date they were granted.

Restricted stock – We grant restricted stock and restricted stock units ("restricted stock awards") under the 2012 Plan and previously granted such awards under the 2007 Plan and the 2003 Plan. The restricted stock awards granted officers vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees, based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Common stock units – We maintain an equity compensation program for our non-employee directors under the 2012 Plan and previously maintained such a program under the 2007 Plan and the 2003 Plan. All non-employee directors receive annual grants of common stock units. Those units granted prior to 2012 must be held until completion of board service, at which time the non-employee director will receive common shares. Common shares will be issued for units granted on or after January 1, 2012 upon completion of board service or three years from the date of grant, whichever is earlier. When dividends are paid on our common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock based compensation expense

Total employee stock based compensation expense was $70 million, $65 million and $51 million in 2012, 2011 and 2010, while the total related income tax benefits were $25 million, $23 million and $19 million in the same years. In 2012, 2011 and 2010, cash received upon exercise of stock option awards was $41 million, $77 million and $12 million. Tax benefits realized for deductions for stock awards exercised during 2012, 2011 and 2010 totaled $24 million, $32 million and $11 million.

Stock option awards

During 2012, 2011 and 2010, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following Black-Scholes assumptions:

	2012	2011	2010
Weighted average exercise price per share	$33.52	$32.30	$30.00
Expected annual dividend yield	2.2%	2.1%	3.2%
Expected life in years	5.6	5.3	5.1
Expected volatility	41%	40%	43%
Risk-free interest rate	1.2%	1.7%	2.2%
Weighted average grant date fair value of stock option awards granted	$10.86	$10.44	$8.70

The following is a summary of stock option award activity in 2012.

	Number of Shares	Weighted Average Exercise price
Outstanding at beginning of year	21,370,715	$24.41
Granted	1,858,872	$33.52
Exercised	(2,795,612)	$16.46
Cancelled	(897,010)	$29.29
Outstanding at end of year	19,536,965	$26.19

The intrinsic value of stock option awards exercised during 2012, 2011 and 2010 was $40 million, $59 million and $8 million.

The following table presents information related to stock option awards at December 31, 2012.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Option	Weighted Average Exercise Price
$ 7.99-12.75	429,685	1	$10.06	429,685	$10.06
12.76-16.81	2,307,526	4	$15.18	2,307,526	$15.18
16.82-23.20	5,409,048	7	$18.60	4,105,057	$18.55
23.21-29.24	2,031,690	5	$24.63	1,599,222	$23.79
29.25-36.03	6,809,564	6	$32.93	3,272,482	$32.50
36.04-46.41	2,549,452	6	$38.25	2,549,452	$38.25
Total	19,536,965	6	$26.19	14,263,424	$25.41

As of December 31, 2012, the aggregate intrinsic value of stock option awards outstanding was $122 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $105 million and 5 years.

As of December 31, 2012, the number of fully-vested stock option awards and stock option awards expected to vest was 19,466,855. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $26.18 and 6 years and the aggregate intrinsic value was $122 million. As of December 31, 2012, unrecognized compensation cost related to stock option awards was $22 million, which is expected to be recognized over a weighted average period of 1 year.

Restricted stock awards

The following is a summary of restricted stock award activity in 2012.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	3,703,978	$25.88
Granted	2,202,774	$31.59
Vested	(1,254,320)	$24.90
Forfeited	(474,548)	$27.26
Unvested at end of year	4,177,884	$29.02

The vesting date fair value of restricted stock awards which vested during 2012, 2011 and 2010 was $36 million, $30 million and $21 million. The weighted average grant date fair value of restricted stock awards was $29.02, $25.88, and $23.03 for awards unvested at December 31, 2012, 2011 and 2010.

As of December 31, 2012, there was $94 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 1.2 years.

Performance unit awards

Performance units provide for executive officers to receive a cash payment upon the achievement of certain performance goals at the end of a defined measurement period. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. The target value of each performance unit is $1, with a maximum payout of $2 per unit, but the actual payout could be anywhere between zero and the maximum. Because performance units are to be settled in cash at the end of the performance period, they are accounted for as liability awards. Compensation expense associated with performance units was $12 million and $32 million in 2012 and 2011, but was not significant in 2010. Expense for 2011 included $14 million paid on three groups of performance unit grants outstanding June 30, 2011, that were accelerated with the total payout determined based on performance through the effective date of the spin-off of our downstream business.

During 2012, we granted 12.7 million performance units. These units have a 36-month performance period. During the third quarter of 2011, we granted 15 million performance units. A portion of the units granted in 2011 had an 18-month performance period and a portion had a 30-month performance period to reflect the remaining periods of the original 2011 and 2010 performance unit grants outstanding prior to the spin-off. The performance period for the units with an 18-month performance period ended December 31, 2012.

22. Stockholders' Equity

Share repurchase plan – The Board of Directors has authorized the repurchase of up to $5 billion of our common stock. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables. As of December 31, 2012, we had acquired 78 million common shares at a cost of $3,222 million under this authorized share repurchase program, including 12 million common shares acquired in 2011 after the June 30, 2011 spin-off of our downstream business at a cost of $300 million.

23. Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations and for operating lease obligations having initial or remaining noncancellable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2013	$ 1	$ 42
2014	1	36
2015	1	33
2016	1	29
2017	1	21
Later years	24	49
Sublease rentals	—	(2)
Total minimum lease payments	$ 29	$ 208
Less imputed interest costs	(18)	
Present value of net minimum lease payments	$ 11	

Operating lease rental expense was $74 million, $74 million and $77 million in 2012, 2011 and 2010, which excludes $16 million paid by United States Steel on assumed leases in 2010.

24. Commitments and Contingencies

We are a defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Litigation – In March 2011, Noble Drilling (U.S.) LLC ("Noble") filed a lawsuit against us in the District Court of Harris County, Texas alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. Noble is seeking an unspecified amount of damages. We are vigorously defending this litigation. The ultimate outcome of this lawsuit, including any financial effect on us, remains uncertain. We do not believe an estimate of a reasonably probable loss (or range of loss) can be made for this lawsuit at this time.

Environmental matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2012 and 2011, accrued liabilities for remediation were not significant. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees – We have various performance guarantees related to specific agreements as discussed below. Under the terms of most of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain facilities formerly owned by United States Steel. We have agreed, under certain circumstances, to indemnify the limited partners if the partnership's product sales fail to qualify for the credit under Section 29 of the Internal Revenue Code. The Clairton 1314B Partnership was terminated on October 31, 2008, but we were not released from our obligations. United States Steel has estimated the maximum potential amount of this indemnity obligation, including interest and tax gross-up, was approximately $110 million as of December 31, 2012.

After our 2009 sale of the subsidiary holding our interest in the Corrib natural gas development offshore Ireland, one guarantee of that entity's performance related to asset retirement obligations remains issued to certain Irish government entities until the Irish government and the current Corrib partners agree to release our guarantee and accept the purchaser's guarantee to replace it. We have been indemnified by the purchaser of the subsidiary and have the benefit of a letter of credit. The maximum potential undiscounted payments related to asset retirement obligations under this guarantee as of December 31, 2012 are $40 million.

We have entered into other guarantees with maximum potential undiscounted payments totaling $94 million as of December 31, 2012, which consist primarily of a performance guarantee and a long-term transportation services agreement.

In October 2010, upon acquiring a position in four exploration blocks in the Kurdistan Region of Iraq, we indemnified the KRG against any negative tax effects related to certain payments we are obligated to make to the KRG. As of December 31, 2012, some of those payments had been made, no related taxes have been assessed, and neither is there any history of such payments being taxed. Given the lack of history of tax assessment against such payments, and because certain of our future payments to the KRG are not quantifiable, a maximum potential undiscounted payments cannot be calculated.

Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Contract commitments – At December 31, 2012 and 2011, contractual commitments to acquire property, plant and equipment totaled $949 million and $615 million.

Other contingencies – During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. Our share of the estimated costs in the amount of $64 million was recorded to cost of revenues in 2011. At December 31, 2012, the remaining liability is $39 million.

Select Quarterly Financial Data (Unaudited)

	2012				2011[(a)]			
(In millions, except per share data)	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Revenues	$ 3,791	$ 3,731	$ 4,034	$ 4,132	$ 3,671	$ 3,694	$ 3,649	$ 3,649
Income from operations before income taxes	1,394	1,475	1,782	1,681	1,289	928	1,333	1,263
Income from continuing operations	417	393	450	322	455	298	405	549
Discontinued operations	—	—	—	—	541	698	—	—
Net income	$ 417	$ 393	$ 450	$ 322	$ 996	$ 996	$ 405	$ 549
Income per share:								
Basic:								
Continuing operations	$0.59	$0.56	$0.64	$0.46	$0.64	$0.42	$0.57	$0.78
Discontinued operations	—	—	—	—	$0.76	$0.98	—	—
Net income	$0.59	$0.56	$0.64	$0.46	$1.40	$1.40	$0.57	$0.78
Diluted:								
Continuing operations	$0.59	$0.56	$0.63	$0.45	$0.64	$0.42	$0.57	$0.78
Discontinued operations	—	—	—	—	$0.75	$0.97	—	—
Net income	$0.59	$0.56	$0.63	$0.45	$1.39	$1.39	$0.57	$0.78
Dividends paid per share	$0.17	$0.17	$0.17	$0.17	$0.25	$0.25	$0.15	$0.15

(a) The downstream business was spun-off on June 30, 2011. All quarters prior to the spin-off have been recast to reflect this business in discontinued operations.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the U.S.; Europe, which primarily includes activities in Norway, Poland and the U.K.; E.G.; Other Africa, which primarily includes activities in Angola, Gabon, Kenya and Libya; Canada; and Other International ("Other Int'l"), which includes activities in Indonesia and the Kurdistan Region of Iraq.

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of liquid hydrocarbons, natural gas and synthetic crude oil is a highly technical process, which is based upon several underlying assumptions that are subject to change. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business – Reserves.

(mmbbl)	U.S.	Canada	E.G.[a]	Other Africa	Europe	Total
Liquid Hydrocarbons						
Proved developed and undeveloped reserves:						
Beginning of year - 2010	170	—	122	228	102	622
Revisions of previous estimates	(3)	—	10	—	23	30
Purchases of reserves in place	1	—	—	—	—	1
Extensions, discoveries and other additions	30	—	—	28	8	66
Production	(25)	—	(13)	(17)	(34)	(89)
End of year - 2010	173	—	119	239	99	630
Revisions of previous estimates	16	—	11	2	21	50
Improved recovery	1	—	—	—	—	1
Purchases of reserves in place	89	—	—	—	—	89
Extensions, discoveries and other additions	27	—	—	1	14	42
Production	(27)	—	(13)	(2)	(37)	(79)
End of year - 2011	279	—	117	240	97	733
Revisions of previous estimates	9	—	6	(5)	28	38
Improved recovery	2	—	—	—	—	2
Purchases of reserves in place	52	—	—	—	—	52
Extensions, discoveries and other additions	172	—	—	7	—	179
Production	(39)	—	(13)	(15)	(36)	(103)
End of year - 2012	475	—	110	227	89	901
Proved developed reserves:						
Beginning of year - 2010	120	—	83	186	87	476
End of year - 2010	124	—	86	180	89	479
End of year - 2011	141	—	78	179	84	482
End of year - 2012	198	—	68	168	84	518
Proved undeveloped reserves:						
Beginning of year - 2010	50	—	39	42	15	146
End of year - 2010	49	—	33	59	10	151

End of year - 2011	138	—	39	61	13	251
End of year - 2012	277	—	42	59	5	383

Estimated Quantities of Proved Oil and Gas Reserves (continued)

	U.S.	Canada	E.G.[a]	Other Africa	Europe	Total
Natural Gas *(bcf)*						
Proved developed and undeveloped reserves:						
Beginning of year - 2010	820	—	1,688	107	109	2,724
Revisions of previous estimates	16	—	111	(1)	35	161
Purchases of reserves in place	1	—	—	—	—	1
Extensions, discoveries and other additions	61	—	—	—	4	65
Production[b]	(133)	—	(148)	(1)	(32)	(314)
Sales of reserves in place	(20)	—	—	—	—	(20)
End of year - 2010	745	—	1,651	105	116	2,617
Revisions of previous estimates	18	—	81	(1)	22	120
Purchases of reserves in place	119	—	—	—	—	119
Extensions, discoveries and other additions	109	—	—	—	11	120
Production[b]	(119)	—	(161)	—	(30)	(310)
End of year - 2011	872	—	1,571	104	119	2,666
Revisions of previous estimates	(29)	—	10	(1)	15	(5)
Purchases of reserves in place	105	—	—	—	—	105
Extensions, discoveries and other additions	224	—	—	111	—	335
Production[b]	(129)	—	(157)	(5)	(31)	(322)
End of year - 2012	1,043	—	1,424	209	103	2,779
Proved developed reserves:						
Beginning of year - 2010	652	—	1,102	107	50	1,911
End of year - 2010	591	—	1,186	104	43	1,924
End of year - 2011	551	—	1,104	104	40	1,799
End of year - 2012	546	—	980	99	28	1,653
Proved undeveloped reserves:						
Beginning of year - 2010	168	—	586	—	59	813
End of year - 2010	154	—	465	1	73	693
End of year - 2011	321	—	467	—	79	867
End of year - 2012	497	—	444	110	75	1,126
Synthetic crude oil *(mmbbl)*						
Proved developed and undeveloped reserves:						
Beginning of year - 2010	—	603	—	—	—	603
Revisions of previous estimates	—	(22)	—	—	—	(22)
Production	—	(9)	—	—	—	(9)
End of year - 2010	—	572	—	—	—	572
Revisions of previous estimates	—	17	—	—	—	17
Production	—	(14)	—	—	—	(14)
Extensions, discoveries and other additions	—	48	—	—	—	48
End of year - 2011	—	623	—	—	—	623
Revisions of previous estimates	—	45	—	—	—	45

Production	—	(15)	—	—	—	(15)
End of year - 2012	—	653	—	—	—	653
Proved developed reserves:						
Beginning of year - 2010	—	392	—	—	—	392
End of year - 2010	—	433	—	—	—	433
End of year - 2011	—	623	—	—	—	623
End of year - 2012	—	653	—	—	—	653
Proved undeveloped reserves:						
Beginning of year - 2010	—	211	—	—	—	211
End of year - 2010	—	139	—	—	—	139
End of year - 2011	—	—	—	—	—	—
End of year - 2012	—	—	—	—	—	—

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmboe)	U.S.	Canada	E.G.[(a)]	Other Africa	Europe	Total
Total Proved Reserves						
Proved developed and undeveloped reserves:						
Beginning of year - 2010	307	603	403	246	120	1,679
Revisions of previous estimates	(1)	(22)	29	—	28	34
Purchases of reserves in place	1	—	—	—	—	1
Extensions, discoveries and other additions	40	—	—	28	9	77
Production[(b)]	(47)	(9)	(38)	(17)	(39)	(150)
Sales of reserves in place	(3)	—	—	—	—	(3)
End of year - 2010	297	572	394	257	118	1,638
Revisions of previous estimates	19	17	25	1	25	87
Improved recovery	1	—	—	—	—	1
Purchases of reserves in place	109	—	—	—	—	109
Extensions, discoveries and other additions	45	48	—	1	16	110
Production[(b)]	(47)	(14)	(40)	(2)	(42)	(145)
End of year - 2011	424	623	379	257	117	1,800
Revisions of previous estimates	5	45	7	(5)	30	82
Improved recovery	2	—	—	—	—	2
Purchases of reserves in place	70	—	—	—	—	70
Extensions, discoveries and other additions	209	—	—	26	—	235
Production[(b)]	(61)	(15)	(39)	(16)	(41)	(172)
End of year - 2012	649	653	347	262	106	2,017
Proved developed reserves:						
Beginning of year - 2010	229	392	267	204	95	1,187
End of year - 2010	222	433	284	198	96	1,233
End of year - 2011	233	623	262	196	91	1,405
End of year - 2012	289	653	231	185	88	1,446
Proved undeveloped reserves:						
Beginning of year - 2010	78	211	136	42	25	492
End of year - 2010	75	139	110	59	22	405
End of year - 2011	191	—	117	61	26	395
End of year - 2012	360	—	116	77	18	571

[(a)] Consists of estimated reserves from properties governed by production sharing contracts.

[(b)] Excludes the resale of purchased natural gas used in reservoir management.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

	December 31,						
(In millions)	U.S.	Canada	E.G.	Other Africa	Europe	Other Int'l	Total
2012 Capitalized Costs:							
Proved properties	$ 21,309	$ 9,003	$ 1,586	$ 2,139	$ 8,778	$ 67	$ 42,882
Unproved properties	3,019	1,473	29	361	72	79	5,033
Total	24,328	10,476	1,615	2,500	8,850	146	47,915
Accumulated depreciation, depletion and amortization:							
Proved properties	10,493	782	824	178	7,191	1	19,469
Unproved properties	293	—	—	9	—	19	321
Total	10,786	782	824	187	7,191	20	19,790
Net capitalized costs	$ 13,542	$ 9,694	$ 791	$ 2,313	$ 1,659	$ 126	$ 28,125
2011 Capitalized Costs:							
Proved properties	$ 15,183	$ 8,810	$ 1,545	$ 1,722	$ 8,314	$ 33	$ 35,607
Unproved properties	4,344	1,473	23	303	51	179	6,373
Total	19,527	10,283	1,568	2,025	8,365	212	41,980
Accumulated depreciation, depletion and amortization:							
Proved properties	8,499	572	729	134	6,593	1	16,528
Unproved properties	359	—	—	9	—	12	380
Total	8,858	572	729	143	6,593	13	16,908
Net capitalized costs	$ 10,669	$ 9,711	$ 839	$ 1,882	$ 1,772	$ 199	$ 25,072

Costs Incurred for Property Acquisition, Exploration and Development[(a)]

(In millions)	U.S.	Canada	E.G.	Other Africa	Europe	Other Int'l	Total
2012 Property acquisition:							
Proved	$ 756	$ —	$ —	$ —	$ 3	$ —	$ 759
Unproved	432	—	18	68	—	(13)	505
Exploration	1,587	31	3	45	54	136	1,856
Development	2,469	195	22	368	468	5	3,527
Total	$ 5,244	$ 226	$ 43	$ 481	$ 525	$ 128	$ 6,647
2011 Property acquisition:							
Proved	$ 1,782	$ 5	$ 1	$ —	$ —	$ —	$ 1,788
Unproved	3,271	—	—	1	7	57	3,336
Exploration	782	42	—	33	109	168	1,134
Development	889	293	18	294	388	—	1,882
Total	$ 6,724	$ 340	$ 19	$ 328	$ 504	$ 225	$ 8,140
2010 Property acquisition:							
Proved	$ 1	$ —	$ —	$ —	$ —	$ —	$ 1
Unproved	400	—	—	1	2	103	506

Exploration	520	10	1	41	43	153	768
Development	855	889	13	315	465	—	2,537
Total	$ 1,776	$ 899	$ 14	$ 357	$ 510	$ 256	$ 3,812

(a) Includes costs incurred whether capitalized or expensed.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

(In millions)	U.S.	Canada	E.G.	Other Africa	Europe	Other Int'l	Total
2012 Revenues and other income:							
Sales	$ 3,873	$ 1,261	$ 30	$ 2,003	$ 840	$ —	$ 8,007
Transfers	2	—	818	—	3,609	—	4,429
Other income[a]	(4)	—	—	—	—	(32)	(36)
Total revenues and other income	3,871	1,261	848	2,003	4,449	(32)	12,400
Expenses:							
Production costs	(1,204)	(922)	(141)	(76)	(376)	—	(2,719)
Exploration expenses	(564)	(31)	(3)	(16)	(42)	(73)	(729)
Depreciation, depletion and amortization[b]	(1,793)	(217)	(95)	(40)	(614)	—	(2,759)
Administrative expenses	(73)	(10)	(3)	(4)	(17)	(19)	(126)
Total expenses	(3,634)	(1,180)	(242)	(136)	(1,049)	(92)	(6,333)
Results before income taxes	237	81	606	1,867	3,400	(124)	6,067
Income tax (provision) benefit	(86)	(20)	(211)	(1,788)	(2,537)	55	(4,587)
Results of operations	$ 151	$ 61	$ 395	$ 79	$ 863	$ (69)	$ 1,480
2011 Revenues and other income:							
Sales	$ 3,063	$ 1,332	$ 29	$ 216	$ 1,010	$ —	$ 5,650
Transfers	63	—	905	—	3,560	—	4,528
Other income[a]	41	—	—	—	15	—	56
Total revenues and other income	3,167	1,332	934	216	4,585	—	10,234
Expenses:							
Production costs[c]	(954)	(814)	(117)	(33)	(350)	—	(2,268)
Exploration expenses	(378)	(10)	(1)	(10)	(81)	(164)	(644)
Depreciation, depletion and amortization[b]	(1,471)	(196)	(104)	(11)	(685)	—	(2,467)
Administrative expenses	(67)	(10)	(2)	(1)	(19)	(15)	(114)
Total expenses	(2,870)	(1,030)	(224)	(55)	(1,135)	(179)	(5,493)
Results before income taxes	297	302	710	161	3,450	(179)	4,741
Income tax (provision) benefit	(104)	(76)	(254)	(168)	(2,203)	63	(2,742)
Results of operations	$ 193	$ 226	$ 456	$ (7)	$ 1,247	$ (116)	$ 1,999
2010 Revenues and other income:							
Sales	$ 2,429	$ 604	$ 11	$ 1,473	$ 697	$ —	$ 5,214
Transfers	93	—	701	—	2,319	—	3,113
Other income[a]	17	—	—	812	(64)	—	765
Total revenues and other income	2,539	604	712	2,285	2,952	—	9,092
Expenses:							
Production costs	(815)	(596)	(108)	(70)	(297)	—	(1,886)
Exploration expenses	(275)	(5)	(21)	(47)	(32)	(118)	(498)
Depreciation, depletion and amortization[b]	(1,463)	(108)	(110)	(36)	(687)	—	(2,404)

Administrative expenses	(52)	(9)	(1)	2	(20)	(10)	(90)
Total expenses	(2,605)	(718)	(240)	(151)	(1,036)	(128)	(4,878)
Results before income taxes	(66)	(114)	472	2,134	1,916	(128)	4,214
Income tax (provision) benefit	26	28	(187)	(1,647)	(658)	46	(2,392)
Results of operations	$ (40)	$ (86)	$ 285	$ 487	$ 1,258	$ (82)	$ 1,822

[a] Includes net gain(loss) on dispositions.

[b] Includes long-lived asset impairments.

[c] 2011 Canada production costs include $64 million accrued for Oil Sands water abatement.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of operations for oil and gas producing activities to segment income:

(In millions)	2012	2011	2010
Results of operations	$ 1,480	$ 1,999	$ 1,822
Items not included in results of oil and gas operations, net of tax:			
Marketing income and technology costs	94	(10)	55
Income from equity method investments	206	213	167
Other third-party income[(a)]	6	10	(5)
Other	8	(2)	(2)
Items not allocated to segment income, net of tax:			
Loss (gain) on asset disposition	32	(23)	(449)
Long-lived asset impairments	231	178	303
Water abatement-Oil Sands	—	48	—
Segment income not included in results of oil and gas operations:			
Integrated Gas	91	178	142
Segment income	$ 2,148	$ 2,591	$ 2,033

[(a)] Includes revenues, net of associated costs and income taxes, from activities that support our production operations, which may include processing or transportation of third-party production and the purchase and subsequent resale of natural gas utilized for reservoir management.

Standardized Measure of Discounted Future Net Cash Flows

	December 31,					
(In millions)	U.S.	Canada	E.G.	Other Africa	Europe	Total
2012						
Future cash inflows	$ 42,710	$ 55,171	$ 6,627	$ 29,993	$ 11,271	$ 145,772
Future production and administrative costs	(13,765)	(32,131)	(1,829)	(1,315)	(2,302)	(51,342)
Future development costs	(11,104)	(9,350)	(451)	(1,119)	(1,673)	(23,697)
Future income tax expenses	(4,489)	(2,948)	(1,191)	(25,370)	(5,275)	(39,273)
Future net cash flows	$ 13,352	$ 10,742	$ 3,156	$ 2,189	$ 2,021	$ 31,460
10 percent annual discount for estimated timing of cash flows	(6,956)	(7,842)	(1,178)	(939)	(326)	(17,241)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 6,396	$ 2,900	$ 1,978	$ 1,250	$ 1,695	$ 14,219
2011						
Future cash inflows	$ 28,108	$ 59,365	$ 7,318	$ 30,007	$ 12,120	$ 136,918
Future production and administrative costs	(10,751)	(28,048)	(1,931)	(1,269)	(2,752)	(44,751)
Future development costs	(6,341)	(10,346)	(435)	(874)	(1,702)	(19,698)
Future income tax expenses	(2,740)	(4,490)	(1,368)	(25,821)	(5,375)	(39,794)
Future net cash flows	$ 8,276	$ 16,481	$ 3,584	$ 2,043	$ 2,291	$ 32,675
10 percent annual discount for estimated timing of cash flows	(4,539)	(11,845)	(1,331)	(733)	(446)	(18,894)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 3,737	$ 4,636	$ 2,253	$ 1,310	$ 1,845	$ 13,781
2010						
Future cash inflows	$ 15,349	$ 41,901	$ 5,366	$ 20,815	$ 8,800	$ 92,231

Future production and administrative costs	(6,878)	(21,675)	(1,469)	(996)	(2,275)	(33,293)
Future development costs	(2,084)	(9,688)	(441)	(907)	(1,535)	(14,655)
Future income tax expenses	(1,726)	(1,821)	(1,208)	(17,201)	(3,108)	(25,064)
Future net cash flows	$ 4,661	$ 8,717	$ 2,248	$ 1,711	$ 1,882	$ 19,219
10 percent annual discount for estimated timing of cash flows	(2,008)	(6,168)	(795)	(825)	(234)	(10,030)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,653	$ 2,549	$ 1,453	$ 886	$ 1,648	$ 9,189

Changes in the Standardized Measure of Discounted Future Net Cash Flows

(In millions)	2012	2011	2010
Sales and transfers of oil and gas produced, net of production and administrative costs	$ (9,632)	$ (7,824)	$ (6,316)
Net changes in prices and production and administrative costs related to future production	(1,527)	12,269	9,839
Extensions, discoveries and improved recovery, less related costs	2,758	1,451	1,268
Development costs incurred during the period	3,550	1,899	2,546
Changes in estimated future development costs	(329)	(1,349)	(2,153)
Revisions of previous quantity estimates[a]	1,475	2,604	1,357
Net changes in purchases and sales of minerals in place	908	233	(20)
Accretion of discount	3,172	2,040	1,335
Net change in income taxes	63	(6,731)	(4,322)
Net change for the year	438	4,592	3,534
Beginning of the year	13,781	9,189	5,655
End of year	$ 14,219	$ 13,781	$ 9,189

[a] Includes amounts resulting from changes in the timing of production and other.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions)	2012	2011	2010
Segment Income (Loss)			
Exploration and Production			
United States	$ 393	$ 366	$ 251
International	1,488	1,791	1,690
E&P segment	1,881	2,157	1,941
Oil Sands Mining	176	256	(50)
Integrated Gas	91	178	142
Segment income	2,148	2,591	2,033
Items not allocated to segments, net of income taxes	(566)	(884)	(151)
Income from continuing operations	1,582	1,707	1,882
Discontinued operations[(a)]	—	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568
Capital Expenditures[(b)]			
Exploration and Production			
United States	$ 3,995	$ 2,145	$ 1,528
International	840	893	946
E&P segment	4,835	3,038	2,474
Oil Sands Mining	188	308	874
Integrated Gas	2	2	2
Corporate	106	51	46
Total	$ 5,131	$ 3,399	$ 3,396
Exploration Expenses			
United States	$ 564	$ 379	$ 275
International	165	265	223
Total	$ 729	$ 644	$ 498

(a) The spin-off of the downstream business was completed on June 30, 2011 and has been reported as discontinued operations in 2011 and 2010.

(b) Capital expenditures include changes in accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	2012	2011	2010
E&P Operating Statistics - Net Sales Volumes			
Crude Oil and Condensate *(mbbld)*			
United States	96	70	66
Europe	96	100	90
Africa	67	32	72
Total International	163	132	162
Worldwide	259	202	228
Natural Gas Liquids *(mbbld)*			
United States	11	5	4
Europe	1	1	2
Africa	11	11	11
Total International	12	12	13
Worldwide	23	17	17
Total Liquid Hydrocarbon *(mbbld)*			
United States	107	75	70
Europe	97	101	92
Africa	78	43	83
Total International	175	144	175
Worldwide	282	219	245
Natural Gas *(mmcfd)*			
United States	358	326	364
Europe(c)	101	97	105
Africa	443	443	409
Total International	544	540	514
Worldwide	902	866	878
Total Worldwide *(mboed)*	432	363	391

(c) Includes natural gas acquired for injection and subsequent resale of 15 mmcfd, 16 mmcfd and 18 mmcfd for the years 2012, 2011 and 2010.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	2012	2011	2010
E&P Operating Statistics - Average Realizations [d]			
Crude Oil and Condensate *(per bbl)*			
United States	$91.29	$94.80	$73.66
Europe	$115.59	$115.88	$82.31
Africa	$114.52	$98.80	$82.16
Total International	$115.15	$111.78	$82.25
Worldwide	$106.35	$105.84	$79.76
Natural Gas Liquids *(per bbl)*			
United States	$39.57	$58.53	$50.71
Europe	$78.81	$78.76	$62.62
Africa	$1.00	$1.00	$1.00
Total International	$8.32	$6.77	$9.37
Worldwide	$23.44	$21.21	$19.75
Total Liquid Hydrocarbon *(per bbl)*			
United States[e]	$85.80	$92.55	$72.30
Europe	$115.16	$115.55	$81.95
Africa	$98.52	$73.21	$71.71
Total International	$107.78	$102.96	$77.11
Worldwide	$99.46	$99.37	$75.73
Natural Gas *(per mcf)*			
United States	$3.91	$4.95	$4.71
Europe	$10.47	$9.84	$7.10
Africa[f]	$0.43	$0.24	$0.25
Total International	$2.29	$1.97	$1.65
Worldwide	$2.94	$3.09	$2.91

[d] Excludes gains or losses on derivative instruments.

[e] Inclusion of realized gains on crude oil derivative instruments would have increased average liquid hydrocarbon realizations by $0.39 per bbl for the year 2012.

[f] Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and EGHoldings, equity method investees. We include our share of Alba Plant LLC's income in our E&P segment and we include our share of AMPCO's and EGHoldings' income in our IG segment.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	2012	2011	2010
OSM Operating Statistics			
Net Synthetic Crude Oil Sales *(mbbld)*[g]	47	43	29
Synthetic Crude Oil Average Realizations *(per bbl)*[d]	$81.72	$91.65	$71.06
IG Operating Statistics			
Net Sales *(mtd)*			
LNG[h]	6,290	7,086	6,859
Methanol	1,298	1,282	1,049
Total Proved Reserves *(at year end)*			
Liquid Hydrocarbon *(mmbbl)*			
United States	475	279	173
International	426	454	457
Worldwide	901	733	630
Natural Gas *(bcf)*			
United States	1,043	872	745
International	1,736	1,794	1,872
Worldwide	2,779	2,666	2,617
Synthetic Crude Oil *(mmbbl)*			
Canada	653	623	572
Total Proved Reserves *(mmboe)*	2,017	1,800	1,638

[g] Includes blendstocks.

[h] Includes both consolidated sales volumes and our share of the sales volumes of equity method investees in 2011 and 2010. LNG sales from Alaska, conducted through a consolidated subsidiary, ceased when these operations were sold in the third quarter of 2011. LNG and methanol sales from E.G. are conducted through equity method investees.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this Report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as of December 31, 2012.

Internal Control Over Financial Reporting

In 2012, we began a project to update our existing ERP system. The project includes implementation of a new general ledger, consolidations system and reporting tools. This project is currently in testing phases and we expect full implementation in the first half of 2013. We believe that controls over project development and implementation are adequate to assure there will be no material effect, or a reasonable likelihood of a material effect, on our internal control over financial reporting.

During the fourth quarter of 2012, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting. See Item 8. Financial Statements and Supplementary Data — Management's Report on Internal Control over Financial Reporting and – Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information concerning our directors required by this item is incorporated by reference to the material appearing under the heading "Election of Directors" in our Proxy Statement for the 2013 Annual Meeting of Stockholders.

Our Board of Directors has established the Audit and Finance Committee and determined our "Audit Committee Financial Expert." The related information required by this item is incorporated by reference to the material appearing under the sub-heading "Audit and Finance Committee" located under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2013 Annual Meeting of Stockholders.

We have adopted a Code of Ethics for Senior Financial Officers. It is available on our website at http://marathonoil.com/Code_Ethics_Sr_Finan_Off.

Executive Officers of the Registrant

See Item 1. Business – Executive Officers of the Registrant for the names, ages and titles of our executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires that our directors and executive officers, and persons who own more than ten percent of a registered class of our equity securities, file reports of beneficial ownership on Form 3 and changes in beneficial ownership on Form 4 or Form 5 with the SEC. Based solely on our review of the reporting forms and written representations provided to us from the individuals required to file reports, we believe that each of our directors and executive officers has complied with the applicable reporting requirements for transactions in Marathon Oil securities during the fiscal year ended December 31, 2012.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to the material appearing under the heading "Executive Compensation Tables and Other Information," under the sub-headings "Compensation Committee" and "Compensation Committee Interlocks and Insider Participation," under the heading "The Board of Directors and Governance Matters" and under the heading "Compensation Committee Report" in our Proxy Statement for the 2013 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information concerning security ownership of certain beneficial owners and management required by this item is incorporated by reference to the material appearing under the headings "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Executive Officers" in our Proxy Statement for the 2013 Annual Meeting of Stockholders.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2012 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

- Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan")
- Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") – No additional awards will be granted under this plan.
- Marathon Oil Corporation 2003 Incentive Compensation Plan (the "2003 Plan") – No additional awards will be granted under this plan.

- Deferred Compensation Plan for Non-Employee Directors – No additional awards will be granted under this plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights[c]	Number of securities remaining available for future issuance under equity compensation plans	
Equity compensation plans approved by stockholders	20,452,668	(a)	$26.19	48,601,445	(d)
Equity compensation plans not approved by stockholders	20,984	(b)	N/A	—	
Total	20,473,652		N/A	48,601,445	

(a) Includes the following:

- 393,423 stock options outstanding under the 2012 Plan;
- 15,827,248 stock options outstanding under the 2007 Plan;
- 2,883,833 stock options outstanding under the 2003 Plan and the net number of stock-settled SARs that could be issued from this Plan. The number of stock-settled SARs is based on the closing price of Marathon Oil common stock on December 31, 2012 of $30.66 per share;
- 317,872 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2012 Plan, 2007 Plan and 2003 Plan; common stock units credited under the 2012 Plan, 2007 Plan and 2003 Plan were 44,195, 222,416 and 51,261, respectively;
- 1,030,292 restricted stock units granted to non-officers under the 2012 Plan and 2007 Plan and outstanding as of December 31, 2012.

In addition to the awards reported above 764,348 and 2,388,160 shares of restricted stock were issued and outstanding as of December 31, 2012, but subject to forfeiture restrictions under the 2012 Plan and 2007 Plan, respectively.

(b) Reflects awards of common stock units made to non-employee directors under the Deferred Compensation Plan for Non-Employee Directors prior to April 30, 2003. When a non-employee director leaves the Board, he or she will be issued actual shares of Marathon Oil common stock in place of the common stock units.

(c) Weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

(d) Reflects the shares available for issuance under the 2012 Plan. No more than 19,739,085 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, canceled or expire unexercised shall again immediately become available for issuance.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

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

Information required by this item is incorporated by reference to the material appearing under the heading "Certain Relationships and Related Person Transactions," and under the sub-heading "Board and Committee Independence" under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2013 Annual Meeting of Stockholders.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated by reference to the material appearing under the heading "Information Regarding the Independent Registered Public Accounting Firm’s Fees, Services and Independence" in our Proxy Statement for the 2013 Annual Meeting of Stockholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements (see Part II, Item 8. of this Report regarding financial statements)

2. Financial Statement Schedules

Financial statement schedules required under SEC rules but not included in this Report are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

3. Exhibits:

References to Marathon Ashland Petroleum LLC or MAP are references to the entity now known as Marathon Petroleum Corporation.

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
2	**Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession**						
2.1++	Separation and Distribution Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Oil Company and Marathon Petroleum Corporation	8-K	2.1	5/26/2011	001-05153		
2.2++	Purchase and Sale Agreement between Hilcorp Resources Holding, LP and Marathon Oil Company dated as of May 31, 2011	10-Q/A	2.2	10/18/2011	001-05153		
3	**Articles of Incorporation and Bylaws**						
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	8-K	3.1	4/25/2007	001-05153		
3.2	Amended By-Laws of Marathon Oil Corporation	10-Q	3.1	11/7/2012	001-05153		
3.3	Specimen of Common Stock Certificate	8-K	3.3	5/14/2007	001-05153		
4	**Instruments Defining the Rights of Security Holders, Including Indentures**						
4.1	Credit Agreement, dated as of April 5, 2012, among Marathon Oil Corporation, The Royal Bank of Scotland plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and UBS Securities LLC, as documentation agents, JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions named therein.	8-K	4.1	4/10/2012	001-05153		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
4.2	Indenture, dated as of February 26, 2002, between Marathon Oil Corporation and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon Oil Corporation. Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10 percent of the total consolidated assets of Marathon Oil. Marathon Oil hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request.	S-3	4.4	7/26/2007	333-144874		
10	**Material Contracts**						
10.1	Tax Sharing Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Petroleum Corporation and MPC Investment LLC	8-K	10.1	5/26/2011	001-05153		
10.2	Employee Matters Agreement dated as of May 25, 2011 among Marathon Oil Corporation and Marathon Petroleum Corporation	8-K	10.2	5/26/2011	001-05153		
10.3	Amendment to Employee Matters Agreement dated as of June 30, 2011 between Marathon Oil Corporation and Marathon Petroleum Corporation	10-Q	10.3	8/8/2011	001-05153		
10.4	Marathon Oil Corporation 2012 Incentive Compensation Plan	DEF 14A	App. III	3/8/2012	001-05153		
10.5	Form of Nonqualified Stock Option Award Agreement for Section 16 reporting Officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.6	Form of Nonqualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.7	Form of Restricted Stock Award Agreement for Section 16 reporting Officers granted under Marathon Oil Corporation's 2012 Incentive					X	

	Compensation Plan (3-year cliff vesting)	
10.8	Form of Restricted Stock Award Agreement for Officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year cliff vesting)	X

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.9	Form of Restricted Stock Award Agreement for Section 16 reporting Officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.10	Form of Restricted Stock Award Agreement for Officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.11	Form of Nonqualified Stock Option Award Agreement for non-officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.12	Form of Nonqualified Stock Option Award Agreement for non-officers in Canada granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.13	Form of Restricted Stock Award Agreement for non-officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.14	Form of Restricted Stock Award Agreement for non-officers granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting)					X	
10.15	Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/29/2012	001-05153		
10.16	Form of Nonqualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective May 30, 2007	10-K	10.6	2/29/2012	001-05153		
10.17	Form of Nonqualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan, effective February 24, 2010	10-K	10.5	2/28/2011	001-05153		
10.18	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan, effective May 30, 2007	10-K	10.8	2/29/2012	001-05153		
10.19	Form of Officer Restricted Stock Award Agreement for Section 16	10-K	10.7	2/28/2011	001-05153		

officers granted under Marathon Oil
Corporation’s 2007 Incentive
Compensation Plan, effective
February 24, 2010

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.20	Form of Performance Unit Award Agreement (18 month Performance Cycle) for Section 16 Officers granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan, effective July 27, 2011	10-K	10.10	2/29/2012	001-05153		
10.21	Form of Performance Unit Award Agreement (18 month Performance Cycle) for Officers granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan, effective July 27, 2011	10-K	10.11	2/29/2012	001-05153		
10.22	Form of Performance Unit Award Agreement (30 month Performance Cycle) for Section 16 Officers granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan, effective July 27, 2011	10-K	10.12	2/29/2012	001-05153		
10.23	Form of Performance Unit Award Agreement (30 month Performance Cycle) for Officers granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan, effective July 27, 2011	10-K	10.13	2/29/2012	001-05153		
10.24	Form of Restricted Stock Award Agreement for Section 16 officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan.	10-K	10.27	2/26/2010	001-05153		
10.25	Form of Performance Unit Award Agreement (2010-2012 Performance Cycle) granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan	10-K	10.25	2/26/2010	001-05153		
10.26	Form of Nonqualified Stock Option Award Agreement granted under Marathon Oil Corporation’s 2007 Incentive Compensation Plan	10-K	10.26	2/26/2010	001-05153		
10.27	Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003	10-K	10.9	2/26/2010	001-05153		
10.28	Form of Nonqualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.15	2/26/2010	001-05153		
10.29	Form of Nonqualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.16	2/26/2010	001-05153		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.30	Form of Nonqualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.17	2/26/2010	001-05153		
10.31	Form of Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.19	2/26/2010	001-05153		
10.32	Form of Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.20	2/26/2010	001-05153		
10.33	Form of Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.21	2/26/2010	001-05153		
10.34	Form of Nonqualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan	10-K	10.22	2/26/2010	001-05153		
10.35	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan	10-K	10.23	2/26/2010	001-05153		
10.36	Form of Performance Unit Award Agreement (2005-2007 Performance Cycle) granted under Marathon Oil Corporation’s 2003 Incentive Compensation Plan	10-K	10.24	2/26/2010	001-05153		
10.37	Form of Nonqualified Stock Option Award Agreement for MAP officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.18	2/26/2010	001-05153		
10.38	Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated), Effective January 1, 2002	10-Q	10.1	11/7/2008	001-05153		
10.39	First Amendment to Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated), Effective February 1, 2007	10-Q	10.2	11/7/2008	001-05153		
10.40	Marathon Oil Corporation Deferred Compensation Plan for Non-	10-K	10.14	2/27/2009	001-05153		

	Employee Directors (Amended and Restated as of January 1, 2009)				
10.41	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011	10-K	10.32	2/29/2012	001-05153

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.42	Marathon Oil Company Excess Benefit Plan Amended and Restated	10-K	10.31	2/29/2012	001-05153		
10.43	Marathon Oil Executive Change in Control Severance Benefits Plan, effective as of December 31, 2008	10-K	10.35	2/27/2009	001-05153		
10.44	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011	001-05153		
10.45	Marathon Oil Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009	10-K	10.32	2/27/2009	001-05153		
10.46	Severance Letter Agreement from Mr. David E. Roberts, Jr. dated December 14, 2012	8-K	99.1	12/7/2012	001-05153		
12.1	Computation of Ratio of Earnings to Fixed Charges					X	
14.1	Code of Ethics for Senior Financial Officers	10-K	14.1	2/26/2010	001-05153		
21.1	List of Significant Subsidiaries					X	
23.1	Consent of Independent Registered Public Accounting Firm					X	
23.2	Consent of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists					X	
23.3	Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists					X	
23.4	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists					X	
31.1	Certification of Chairman, President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
31.2	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
32.1	Certification of Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350					X	
32.2	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350					X	
99.1	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2012					X	

99.2	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2011	10-K	99.1	2/29/2012	001-05153
99.3	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2010	10-K	99.1	2/28/2011	001-05153

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
99.4	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2012					X	
99.5	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2011	10-K	99.4	2/29/2012	001-05153		
99.6	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2012					X	
99.7	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2011	10-K	99.5	2/29/2012	001-05153		
101.INS	XBRL Instance Document					X	
101.SCH	XBRL Taxonomy Extension Schema					X	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase					X	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase					X	
101.LAB	XBRL Taxonomy Extension Label Linkbase					X	
101.DEF	XBRL Taxonomy Extension Definition Linkbase					X	

++ **Marathon Oil agrees to furnish supplementally a copy of any omitted schedule to the SEC upon request.**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 22, 2013

MARATHON OIL CORPORATION

By: /s/ MICHAEL K. STEWART

Michael K. Stewart

Vice President, Finance and Accounting, Controller and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 22, 2013 on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ CLARENCE P. CAZALOT, JR. Clarence P. Cazalot, Jr.	Chairman, President and Chief Executive Officer and Director
/s/ JANET F. CLARK Janet F. Clark	Executive Vice President and Chief Financial Officer
/s/ MICHAEL K. STEWART Michael K. Stewart	Vice President, Finance and Accounting, Controller and Treasurer
/s/ GREGORY H. BOYCE Gregory H. Boyce	Director
/s/ PIERRE BRONDEAU Pierre Brondeau	Director
/s/ LINDA Z. COOK Linda Z. Cook	Director
/s/ SHIRLEY ANN JACKSON Shirley Ann Jackson	Director
/s/ PHILIP LADER Philip Lader	Director
/s/ MICHAEL E. J. PHELPS Michael E. J. Phelps	Director
/s/ DENNIS H. REILLEY Dennis H. Reilley	Director

Exhibit 10.5

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

NONQUALIFIED STOCK OPTION AWARD AGREEMENT

[GRANT DATE]

Section 16 Officer

Pursuant to this Award Agreement, MARATHON OIL CORPORATION (the "Corporation") hereby grants to **[NAME]** (the "Optionee"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), a right (the "Option") to purchase from the Corporation **[NUMBER]** shares of Common Stock of the Corporation at a grant price of **$[PRICE]** per share (the "Grant Price"), pursuant to the Marathon Oil Corporation 2012 Incentive Compensation Plan (the "Plan"), with such number of shares and such price per share being subject to adjustment as provided in Section 13 of the Plan, and further subject to the following terms and conditions:

1. **Relationship to the Plan.** This Option is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Sections 12 and 13 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Optionee also include the heirs or other legal representatives of the Optionee.

2. **Exercise and Vesting Schedule.**

(a) This Option shall become exercisable in three cumulative annual installments, as follows:

(i) one-third of the Option Shares shall become exercisable on the first anniversary of the Grant Date;

(ii) an additional one-third of the Option Shares shall become exercisable on the second anniversary of the Grant Date; and

(iii) the remaining one-third of the Option Shares shall become exercisable on the third anniversary of the Grant Date;

provided, however, that the Optionee must be in continuous Employment from the Grant Date through the date of exercisability of each installment in order for the Option to become exercisable with respect to additional shares of Common Stock on such date. If the Employment of the Optionee is terminated for any reason other than death or Retirement, any Option Shares that are not exercisable as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) This Option shall become fully exercisable, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Optionee's Employment due to death;

(ii) termination of the Optionee's Employment due to Retirement; or

(ii) a Change in Control of the Corporation, provided that as of such Change in Control the Optionee had been in continuous Employment since the Grant Date.

3. Expiration of Option.

(a) Expiration of Option Period. The Option Period shall expire on the tenth anniversary of the Grant Date.

(b) Termination of Employment Due to Death or Retirement. If Employment of the Optionee is terminated due to death or Retirement, the Option shall expire upon the earlier of (i) five years following the date of termination of Employment or (ii) expiration of the Option Period. The death of the Optionee following Retirement but prior to the expiration of the Option shall have no effect on the expiration of the Option.

(c) Termination of Employment by the Corporation for Cause or Due to Resignation. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for Cause or due to voluntary resignation by the Optionee, the Option shall expire upon the termination of Employment.

(d) Termination of Employment by the Corporation Other Than For Cause. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for any reason other than Cause, the Option shall expire upon the earlier of (i) 90 days following the date of termination of Employment or (ii) expiration of the Option Period.

(e) Termination of Employment Following or in Connection with a Change in Control. If Employment of the Optionee is terminated following a Change in Control or in connection with a Change in Control, and, as a result, the Optionee is eligible for severance benefits under a Change in Control Agreement, the Option shall remain exercisable throughout the Option Period.

4. Employment with a Competitor. Notwithstanding anything herein to the contrary, in the event the Committee, the Chief Executive Officer, or an authorized officer determines that the Optionee has accepted or intends to accept employment with a competitor of any business unit of the Corporation, the Committee, the Chief Executive Officer, or the authorized officer may cancel the Option by written notice to the Optionee.

5. Forfeiture or Repayment Resulting from Forfeiture Event.

(a) Forfeiture of Unexercised Option. If a Forfeiture Event occurs during the Optionee's Employment or within three years following Optionee's termination of Employment, the Committee may, but is not obligated to, cause all or any portion of the Option granted under this Award Agreement to be forfeited.

(b) Repayment of Spread on Exercised Option. If a Forfeiture Event occurs during the Optionee's Employment or within three years following Optionee's termination of Employment, the Committee may, but is not obligated to, require the Optionee to pay to the Corporation an amount in cash up to (but not in excess of) the difference between the Grant Price and market price of the Option on the date of exercise with respect to any shares for which the Option has been exercised (the "Forfeited Spread Amount"). Any Forfeited Spread Amount shall be paid by the Participant within sixty (60) days of receipt from the Corporation of written notice requiring payment of such Forfeited Spread Amount.

(c) Application of Forfeiture Provisions. This Section 5 shall apply notwithstanding any provision of this Award Agreement to the contrary and is meant to provide the Corporation with rights in addition to any other remedy which may exist in law or in equity. This Section 5 shall not apply to the Optionee following the effective time of a Change in Control.

6. Exercise of Option. Subject to the limitations set forth herein and in the Plan, this Option may be exercised in whole or in part by providing notice to the Committee or its designated representative of the number of Option Shares to be exercised. Such notice shall be accompanied by payment of the Grant Price of such Option Shares in cash or, at the election of the Optionee, in shares of Common Stock or any combination thereof. For purposes of determining the amount, if any, of the purchase price satisfied by payment in Common Stock, such Common Stock shall be valued at its Fair Market Value on the date of exercise. Upon receipt of the purchase price, the Corporation or its designated representative shall issue or cause to be issued to the Optionee a number of shares of Common Stock equal to the number of Option Shares then exercised.

7. Taxes. The Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise payable to the Optionee upon exercise of the Option or from compensation otherwise payable to the Optionee at the time of exercise pursuant to Section 10 of the Plan.

8. Shareholder Rights. The Optionee shall have no rights of a shareholder with respect to the Option Shares unless and until such time as the Option has been exercised and shares of Common Stock have been issued to the Optionee in conjunction with the exercise of the Option.

9. Nonassignability. During the Optionee's lifetime, the Option may be exercised only by the Optionee or by the Optionee's guardian or legal representative. Upon the Optionee's death, the Option shall be transferred to the Optionee's estate. Otherwise, the Optionee may not sell, transfer, assign, pledge or otherwise encumber any portion of the Option, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Option shall have no effect.

10. No Employment Guaranteed. Nothing in this Award Agreement shall give the Optionee any rights to (or impose any obligations for) continued Employment by the Corporation or any Affiliate thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Optionee.

11. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Optionee, adversely affect the rights of the Optionee hereunder.

12. Data Privacy. By accepting the Option subject to the terms of this Award Agreement, the Optionee hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Optionee's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Optionee's employer, (collectively referred to as “Marathon Oil” in this Section 11) for the exclusive purpose of implementing, administering and managing the Optionee's participation in the Plan. The Optionee understands and acknowledges that Marathon Oil holds certain personal information about the Optionee, including, but not limited to, the Optionee's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Optionee's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as “Data” for purposes of this Section 11). The Optionee understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Optionee's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Optionee's country of citizenship or country of residence. The Optionee, by acceptance of the Option subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Optionee's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Optionee may elect to deposit any shares of stock acquired upon exercise or settlement of the grant.

13. Definitions. For purposes of this Award Agreement:

“Cause” means termination from Employment by the Corporation or its Subsidiaries due to unacceptable performance, gross misconduct, gross negligence, material dishonesty, material acts detrimental or destructive to the Corporation or its Subsidiaries, employees or property, or any material violation of the policies of the Corporation or its Subsidiaries.

“Change in Control,” unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a “Person”) is or becomes the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

"Change in Control Agreement" means any plan, program, agreement, or arrangement under which the Corporation or a Subsidiary agrees to provide benefits to the Optionee in the event he or she is terminated following a Change in Control or in connection with a Change in Control, as applicable to the Optionee at the relevant time.

"Employment" means employment with the Corporation or any of its Subsidiaries. For purposes of this Option, Employment shall also include any period of time during which the Optionee is on Disability status.

"Forfeiture Event" means the occurrence of at least one of the following (a) the Corporation is required, pursuant to a determination made by the Securities and Exchange Commission or by the Audit Committee of the Board, to prepare a material accounting restatement due to the noncompliance of the Corporation with any financial reporting requirement under applicable securities laws as a result of misconduct, and the Committee determines that (1) the Optionee knowingly engaged in the misconduct, (2) the Optionee was grossly negligent with respect to such misconduct or (3) the Optionee knowingly or grossly negligently failed to prevent the misconduct or (b) the Committee concludes that the Optionee engaged in fraud, embezzlement or other similar misconduct materially detrimental to the Corporation.

"Option Period" means the period commencing upon the Optionee's receipt of this Award Agreement and ending on the date on which the Option expires pursuant to Section 3.

"Option Shares" means the shares of Common Stock covered by this Option.

Exhibit 10.6

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

NONQUALIFIED STOCK OPTION AWARD AGREEMENT

[GRANT DATE]

Officer

Pursuant to this Award Agreement, MARATHON OIL CORPORATION (the "Corporation") hereby grants to **[NAME]** (the "Optionee"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), a right (the "Option") to purchase from the Corporation **[NUMBER]** shares of Common Stock of the Corporation at a grant price of **$[PRICE]** per share (the "Grant Price"), pursuant to the Marathon Oil Corporation 2012 Incentive Compensation Plan (the "Plan"), with such number of shares and such price per share being subject to adjustment as provided in Section 13 of the Plan, and further subject to the following terms and conditions:

1. **Relationship to the Plan.** This Option is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Sections 11 and 12 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Optionee also include the heirs or other legal representatives of the Optionee.

2. **Exercise and Vesting Schedule.**

(a) This Option shall become exercisable in three cumulative annual installments, as follows:

(i) one-third of the Option Shares shall become exercisable on the first anniversary of the Grant Date;

(ii) an additional one-third of the Option Shares shall become exercisable on the second anniversary of the Grant Date; and

(iii) the remaining one-third of the Option Shares shall become exercisable on the third anniversary of the Grant Date;

provided, however, that the Optionee must be in continuous Employment from the Grant Date through the date of exercisability of each installment in order for the Option to become exercisable with respect to additional shares of Common Stock on such date. If the Employment of the Optionee is terminated for any reason other than death or Retirement, any Option Shares that are not exercisable as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) This Option shall become fully exercisable, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Optionee's Employment due to death;

(ii) termination of the Optionee's Employment due to Retirement; or

(ii) a Change in Control of the Corporation, provided that as of such Change in Control the Optionee had been in continuous Employment since the Grant Date.

3. Expiration of Option.

(a) Expiration of Option Period. The Option Period shall expire on the tenth anniversary of the Grant Date.

(b) Termination of Employment Due to Death or Retirement. If Employment of the Optionee is terminated due to death or Retirement, the Option shall expire upon the earlier of (i) five years following the date of termination of Employment or (ii) expiration of the Option Period. The death of the Optionee following Retirement but prior to the expiration of the Option shall have no effect on the expiration of the Option.

(c) Termination of Employment by the Corporation for Cause or Due to Resignation. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for Cause or due to voluntary resignation by the Optionee, the Option shall expire upon the termination of Employment.

(d) Termination of Employment by the Corporation Other Than For Cause. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for any reason other than Cause, the Option shall expire upon the earlier of (i) 90 days following the date of termination of Employment or (ii) expiration of the Option Period.

(e) Termination of Employment Following or in Connection with a Change in Control. If Employment of the Optionee is terminated following a Change in Control or in connection with a Change in Control, and, as a result, the Optionee is eligible for severance benefits under a Change in Control Agreement, the Option shall remain exercisable throughout the Option Period.

4. Employment with a Competitor. Notwithstanding anything herein to the contrary, in the event the Committee, the Chief Executive Officer, or an authorized officer determines that the Optionee has accepted or intends to accept employment with a competitor of any business unit of the Corporation, the Committee, the Chief Executive Officer, or the authorized officer may cancel the Option by written notice to the Optionee.

5. Exercise of Option. Subject to the limitations set forth herein and in the Plan, this Option may be exercised in whole or in part by providing notice to the Committee or its designated representative of the number of Option Shares to be exercised. Such notice shall be accompanied by payment of the Grant Price of such Option Shares in cash or, at the election of the Optionee, in shares of Common Stock or any combination thereof. For purposes of determining the amount, if any, of the purchase price satisfied by payment in Common Stock, such Common Stock shall be valued at its Fair Market Value on the date of exercise. Upon receipt of the purchase price, the Corporation or its designated representative shall issue or cause to be issued to the Optionee a number of shares of Common Stock equal to the number of Option Shares then exercised.

6. Taxes. The Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise payable to the Optionee upon exercise of the Option or from compensation otherwise payable to the Optionee at the time of exercise pursuant to Section 10 of the Plan.

7. Shareholder Rights. The Optionee shall have no rights of a shareholder with respect to the Option Shares unless and until such time as the Option has been exercised and shares of Common Stock have been issued to the Optionee in conjunction with the exercise of the Option.

8. Nonassignability. During the Optionee's lifetime, the Option may be exercised only by the Optionee or by the Optionee's guardian or legal representative. Upon the Optionee's death, the Option shall be transferred to the Optionee's estate. Otherwise, the Optionee may not sell, transfer, assign, pledge or otherwise encumber any portion of the Option, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Option shall have no effect.

9. No Employment Guaranteed. Nothing in this Award Agreement shall give the Optionee any rights to (or impose any obligations for) continued Employment by the Corporation or any Affiliate thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Optionee.

10. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Optionee, adversely affect the rights of the Optionee hereunder.

11. Data Privacy. By accepting the Option subject to the terms of this Award Agreement, the Optionee hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Optionee's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Optionee's employer, (collectively referred to as “Marathon Oil” in this Section 11) for the exclusive purpose of implementing, administering and managing the Optionee's participation in the Plan. The Optionee understands and acknowledges that Marathon Oil holds certain personal information about the Optionee, including, but not limited to, the Optionee's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Optionee's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as “Data” for purposes of this Section 11). The Optionee understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Optionee's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Optionee's country of citizenship or country of residence. The Optionee, by acceptance of the Option subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Optionee's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Optionee may elect to deposit any shares of stock acquired upon exercise or settlement of the grant.

12. Definitions. For purposes of this Award Agreement:

“Cause” means termination from Employment by the Corporation or its Subsidiaries due to unacceptable performance, gross misconduct, gross negligence, material dishonesty, material acts detrimental or destructive to the Corporation or its Subsidiaries, employees or property, or any material violation of the policies of the Corporation or its Subsidiaries.

“Change in Control,” unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a “Person”) is or becomes the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term “Person” shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an “Excluded Transaction”) which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“Change in Control Agreement” means any plan, program, agreement, or arrangement under which the Corporation or a Subsidiary agrees to provide benefits to the Optionee in the event he or she is terminated following a Change in Control or in connection with a Change in Control, as applicable to the Optionee at the relevant time.

“Employment” means employment with the Corporation or any of its Subsidiaries. For purposes of this Option, Employment shall also include any period of time during which the Optionee is on Disability status.

“Option Period” means the period commencing upon the Optionee's receipt of this Award Agreement and ending on the date on which the Option expires pursuant to Section 3.

“Option Shares” means the shares of Common Stock covered by this Option.

Exhibit 10.7

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

SECTION 16 OFFICER RESTRICTED STOCK AWARD AGREEMENT

[GRANT DATE]

Pursuant to this Award Agreement and the Marathon Oil Corporation 2012 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), **[NUMBER]** restricted shares of Common Stock ("Restricted Shares"). The number of Restricted Shares awarded is subject to adjustment as provided in Section 13 of the Plan, and the Restricted Shares are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Restricted Shares is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations, if any, that have been adopted by the Committee. Except as defined in this Award Agreement (including in Sections 10 and 11), capitalized terms shall have the same meanings given to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan.

2. Vesting and Forfeiture of Restricted Shares.

(a) The Restricted Shares shall vest on the third anniversary of the Grant Date; provided, however, that the Participant must be in continuous Employment from the Grant Date through the vesting date in order for the Restricted Shares to vest. If the Employment of the Participant is terminated for any reason (including non-Mandatory Retirement) other than death or Mandatory Retirement, any Restricted Shares that have not vested as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) The Restricted Shares shall immediately vest in full, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Participant's Employment due to death;

(ii) termination of the Participant's Employment due to Mandatory Retirement; or

(iii) a Change in Control of the Corporation, provided that as of such Change in Control the Participant has been in continuous Employment since the Grant Date.

3. Issuance of Shares. Effective as of the Grant Date, the Committee or its designated representative shall cause a number of shares of Common Stock equal to the number of Restricted Shares to be issued and registered in the Participant's name, subject to the conditions and restrictions set forth in this Award Agreement and the Plan. Such issuance and registration shall be evidenced by an entry on the registry books of the Corporation and, if the Committee so elects, evidenced by a certificate issued by the Corporation. Any book entries and certificates evidencing the Restricted Shares shall carry or be endorsed with a legend referring to the conditions and restrictions set forth in this Award Agreement and the Plan. In the event the Restricted Shares are evidenced by a certificate, such certificate shall be held in custody by the Corporation unless and until the corresponding

Restricted Shares are vested. The Participant shall not be entitled to delivery of a certificate or release of the restrictions on the book entry evidencing such Restricted Shares for any portion of the Restricted Shares unless and until the related Restricted Shares have vested pursuant to Section 2 of this Award Agreement. In the event the Restricted Shares are forfeited in full or in part, the Participant hereby consents to the relinquishment of the forfeited Restricted Shares theretofore issued and registered in the Participant's name to the Corporation at that time.

4. Forfeiture or Repayment Resulting from Forfeiture Event.

(a) If there is a Forfeiture Event either while the Participant is employed or within three years after termination of the Participant's Employment, then the Committee may, but is not obligated to, cause all of the Participant's Restricted Shares to be forfeited by the Participant and returned to the Corporation.

(b) If there is a Forfeiture Event either while the Participant is employed or within three years after termination of the Participant's Employment, then the Committee may, but is not obligated to, require the Participant to pay to the Corporation in cash an amount (the "Forfeiture Amount") up to (but not in excess of) the lesser of (i) the value of such Restricted Shares that have previously vested, determined as of the date such shares vested or (ii) the value of such Restricted Shares that have previously vested, determined as of the date on which the Committee makes a demand for payment of the Forfeiture Amount. Any Forfeiture Amount shall be paid by the Participant within sixty (60) days of receipt from the Corporation of written notice requiring payment of such Forfeiture Amount.

(c) This Section 4 shall apply notwithstanding any provision of this Award Agreement to the contrary and is meant to provide the Corporation with rights in addition to any other remedy which may exist in law or in equity. This Section 4 shall not apply to the Participant following the effective time of a Change in Control.

5. Taxes. Pursuant to Section 10 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise deliverable to the Participant due to the vesting of Restricted Shares pursuant to Section 2 of this Award Agreement, or from other compensation payable to the Participant, at the time of the vesting and delivery of such shares.

6. Shareholder Rights. Unless and until the Restricted Shares are forfeited, the Participant shall have the rights of a shareholder with respect to the Restricted Shares as of the Grant Date, including the right to vote the Restricted Shares and the right to receive dividends. The Participant hereby consents to receiving any dividends on the unvested Restricted Shares through the Corporation's payroll and, accordingly, directs the Corporation's transfer agent to pay such dividends to the Corporation on his or her behalf.

7. Nonassignability. Upon the Participant's death, the Restricted Shares shall be transferred to the Participant's estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Restricted Shares, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Restricted Shares shall have no effect.

8. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary or successor, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

9. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant.

10. Data Privacy. By accepting the Restricted Shares subject to the terms of this Award Agreement, the Participant hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Participant's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Participant's employer, (collectively referred to as “Marathon Oil” in this Section 9) for the exclusive purpose of implementing, administering and managing the Participant's participation in the Plan. The Participant understands and acknowledges that Marathon Oil holds certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Participant's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as “Data” for purposes of this Section 9). The Participant understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Participant's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Participant's country of citizenship or country of residence. The Participant, by acceptance of the Restricted Shares subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Participant's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Participant may elect to deposit the shares following the lapse of applicable restrictions.

11. Definitions. For purposes of this Award Agreement:

“Change in Control,” unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a “Person”) is or becomes the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term “Person” shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an “Excluded Transaction”) which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“Employment” means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

“Forfeiture Event” means the occurrence of at least one of the following (a) the Corporation is required, pursuant to a determination made by the Securities and Exchange Commission or by the Audit Committee of the Board, to prepare a material accounting restatement due to the noncompliance of the Corporation with any financial reporting requirement under applicable securities laws as a result of misconduct, and the Committee determines that (1) the Participant knowingly engaged in the misconduct, (2) the Participant was grossly negligent with respect to such misconduct or (3) the Participant knowingly or grossly negligently failed to prevent the misconduct or (b) the Committee concludes that the Participant engaged in fraud, embezzlement or other similar misconduct materially detrimental to the Corporation.

“Mandatory Retirement” means termination of Employment as a result of the Corporation's policy, if any, requiring the mandatory retirement of officers and/or other employees upon reaching a certain age or milestone.

Exhibit 10.8

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

OFFICER RESTRICTED STOCK AWARD AGREEMENT

[GRANT DATE]

Pursuant to this Award Agreement and the Marathon Oil Corporation 2012 Incentive Compensation Plan (the “Plan”), **MARATHON OIL CORPORATION** (the “Corporation”) hereby grants to **[NAME]** (the “Participant”), an employee of the Corporation or a Subsidiary, on **[DATE]** (the “Grant Date”), **[NUMBER]** restricted shares of Common Stock (“Restricted Shares”). The number of Restricted Shares awarded is subject to adjustment as provided in Section 13 of the Plan, and the Restricted Shares are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Restricted Shares is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations, if any, that have been adopted by the Committee. Except as defined in this Award Agreement (including in Sections 9 and 10 hereof), capitalized terms shall have the same meanings given to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan.

2. Vesting and Forfeiture of Restricted Shares.

(a) The Restricted Shares shall vest on the third anniversary of the Grant Date; provided, however, that the Participant must be in continuous Employment from the Grant Date through the vesting date in order for the Restricted Shares to vest. If the Employment of the Participant is terminated for any reason (including non-Mandatory Retirement) other than death or Mandatory Retirement, any Restricted Shares that have not vested as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) The Restricted Shares shall immediately vest in full, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Participant's Employment due to death;

(ii) termination of the Participant's Employment due to Mandatory Retirement; or

(iii) a Change in Control of the Corporation, provided that as of such Change in Control the Participant has been in continuous Employment since the Grant Date.

3. Issuance of Shares. Effective as of the Grant Date, the Committee or its designated representative shall cause a number of shares of Common Stock equal to the number of Restricted Shares to be issued and registered in the Participant's name, subject to the conditions and restrictions set forth in this Award Agreement and the Plan. Such issuance and registration shall be evidenced by an entry on the registry books of the Corporation and, if the Committee so elects, evidenced by a certificate issued by the Corporation. Any book entries and certificates evidencing the Restricted Shares shall carry or be endorsed with a legend referring to the conditions and restrictions set forth in this Award Agreement and the Plan. In the event the Restricted Shares are evidenced by a certificate, such certificate shall be held in custody by the Corporation unless and until the corresponding Restricted Shares are vested. The Participant shall not be entitled to delivery of a certificate or release of the restrictions on the book entry evidencing such Restricted Shares for any portion of the Restricted Shares unless and until the related Restricted Shares have vested pursuant to Section 2 of this Award Agreement. In the event the Restricted Shares are forfeited in full or in part, the Participant hereby consents to the relinquishment of the forfeited Restricted Shares theretofore issued and registered in the Participant's name to the Corporation at that time.

4. **Taxes.** Pursuant to Section 10 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise deliverable to the Participant due to the vesting of Restricted Shares pursuant to Section 2 of this Award Agreement, or from other compensation payable to the Participant, at the time of the vesting and delivery of such shares.

5. **Shareholder Rights.** Unless and until the Restricted Shares are forfeited, the Participant shall have the rights of a shareholder with respect to the Restricted Shares as of the Grant Date, including the right to vote the Restricted Shares and the right to receive dividends. The Participant hereby consents to receiving any dividends on the unvested Restricted Shares through the Corporation's payroll and, accordingly, directs the Corporation's transfer agent to pay such dividends to the Corporation on his or her behalf.

6. **Nonassignability.** Upon the Participant's death, the Restricted Shares shall be transferred to the Participant's estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Restricted Shares, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Restricted Shares shall have no effect.

7. **No Employment Guaranteed.** Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary or successor, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

8. **Modification of Agreement.** Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant.

9. **Data Privacy.** By accepting the Restricted Shares subject to the terms of this Award Agreement, the Participant hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Participant's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Participant's employer, (collectively referred to as "Marathon Oil" in this Section 9) for the exclusive purpose of implementing, administering and managing the Participant's participation in the Plan. The Participant understands and acknowledges that Marathon Oil holds certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Participant's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as "Data" for purposes of this Section 9). The Participant understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Participant's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Participant's country of citizenship or country of residence. The Participant, by acceptance of the Restricted Shares subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Participant's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Participant may elect to deposit the shares following the lapse of applicable restrictions.

10. Definitions. For purposes of this Award Agreement:

“Change in Control,” unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a “Person”) is or becomes the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term “Person” shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an “Excluded Transaction”) which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“Employment” means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

“Mandatory Retirement” means termination of Employment as a result of the Corporation's policy, if any, requiring the mandatory retirement of officers and/or other employees upon reaching a certain age or milestone.

Exhibit 10.9

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

SECTION 16 OFFICER RESTRICTED STOCK AWARD AGREEMENT

[GRANT DATE]

Pursuant to this Award Agreement and the Marathon Oil Corporation 2012 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), **[NUMBER]** restricted shares of Common Stock ("Restricted Shares"). The number of Restricted Shares awarded is subject to adjustment as provided in Section 13 of the Plan, and the Restricted Shares are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Restricted Shares is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations, if any, that have been adopted by the Committee. Except as defined in this Award Agreement (including in Sections 10 and 11), capitalized terms shall have the same meanings given to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan.

2. Vesting and Forfeiture of Restricted Shares.

(a) The Restricted Shares shall vest in three cumulative annual installments, as follows:

(i) one-third of the Restricted Shares shall vest on the first anniversary of the Grant Date;

(ii) an additional one-third of the Restricted Shares shall vest on the second anniversary of the Grant Date; and

(iii) all remaining Restricted Shares shall vest on the third anniversary of the Grant Date;

provided, however, that the Participant must be in continuous Employment from the Grant Date through the applicable vesting date for each installment in order for the applicable Restricted Shares to vest on such date. If the Employment of the Participant is terminated for any reason, except as provided in subsection (b) below, any Restricted Shares that have not vested as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) The Restricted Shares shall immediately vest in full, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Participant's Employment due to death;

(ii) termination of the Participant's Employment due to Mandatory Retirement; or

(iii) a Change in Control of the Corporation, provided that as of such Change in Control the Participant has been in continuous Employment since the Grant Date.

3. Issuance of Shares. Effective as of the Grant Date, the Committee or its designated representative shall cause a number of shares of Common Stock equal to the number of Restricted Shares to be issued and registered in the Participant's name, subject to the conditions and restrictions set forth in this Award Agreement and the Plan. Such issuance and registration shall be evidenced by an entry on the registry books of the Corporation and, if the Committee so elects, evidenced by a certificate issued by the Corporation. Any book entries and certificates evidencing the Restricted Shares shall carry or be endorsed with a legend referring to the conditions and restrictions set forth in this Award Agreement and the Plan. In the event the Restricted Shares are evidenced by a certificate, such certificate shall be held in custody by the Corporation unless and until the corresponding Restricted Shares are vested. The Participant shall not be entitled to delivery of a certificate or release of the restrictions on the book entry evidencing such Restricted Shares for any portion of the Restricted Shares unless and until the related Restricted Shares have vested pursuant to Section 2 of this Award Agreement. In the event the Restricted Shares are forfeited in full or in part, the Participant hereby consents to the relinquishment of the forfeited Restricted Shares theretofore issued and registered in the Participant's name to the Corporation at that time.

4. Forfeiture or Repayment Resulting from Forfeiture Event.

(a) If there is a Forfeiture Event either while the Participant is employed or within three years after termination of the Participant's Employment, then the Committee may, but is not obligated to, cause all of the Participant's Restricted Shares to be forfeited by the Participant and returned to the Corporation.

(b) If there is a Forfeiture Event either while the Participant is employed or within three years after termination of the Participant's Employment, then the Committee may, but is not obligated to, require the Participant to pay to the Corporation in cash an amount (the "Forfeiture Amount") up to (but not in excess of) the lesser of (i) the value of such Restricted Shares that have previously vested, determined as of the date such shares vested or (ii) the value of such Restricted Shares that have previously vested, determined as of the date on which the Committee makes a demand for payment of the Forfeiture Amount. Any Forfeiture Amount shall be paid by the Participant within sixty (60) days of receipt from the Corporation of written notice requiring payment of such Forfeiture Amount.

(c) This Section 4 shall apply notwithstanding any provision of this Award Agreement to the contrary and is meant to provide the Corporation with rights in addition to any other remedy which may exist in law or in equity. This Section 4 shall not apply to the Participant following the effective time of a Change in Control.

5. Taxes. Pursuant to Section 10 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise deliverable to the Participant due to the vesting of Restricted Shares pursuant to Section 2 of this Award Agreement, or from other compensation payable to the Participant, at the time of the vesting and delivery of such shares.

6. Shareholder Rights. Unless and until the Restricted Shares are forfeited, the Participant shall have the rights of a shareholder with respect to the Restricted Shares as of the Grant Date, including the right to vote the Restricted Shares and the right to receive dividends. The Participant hereby consents to receiving any dividends on the unvested Restricted Shares through the Corporation's payroll and, accordingly, directs the Corporation's transfer agent to pay such dividends to the Corporation on his or her behalf.

7. Nonassignability. Upon the Participant's death, the Restricted Shares shall be transferred to the Participant's estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Restricted Shares, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Restricted Shares shall have no effect.

8. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary or successor, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

9. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant.

10. Data Privacy. By accepting the Restricted Shares subject to the terms of this Award Agreement, the Participant hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Participant's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Participant's employer, (collectively referred to as “Marathon Oil” in this Section 10) for the exclusive purpose of implementing, administering and managing the Participant's participation in the Plan. The Participant understands and acknowledges that Marathon Oil holds certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Participant's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as “Data” for purposes of this Section 10). The Participant understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Participant's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Participant's country of citizenship or country of residence. The Participant, by acceptance of the Restricted Shares subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Participant's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Participant may elect to deposit the shares following the lapse of applicable restrictions.

11. Definitions. For purposes of this Award Agreement:

“Change in Control,” unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a “Person”) is or becomes the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term “Person” shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an “Excluded Transaction”) which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“Employment” means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

“Forfeiture Event” means the occurrence of at least one of the following (a) the Corporation is required, pursuant to a determination made by the Securities and Exchange Commission or by the Audit Committee of the Board, to prepare a material accounting restatement due to the noncompliance of the Corporation with any financial reporting requirement under applicable securities laws as a result of misconduct, and the Committee determines that (1) the Participant knowingly engaged in the misconduct, (2) the Participant was grossly negligent with respect to such misconduct or (3) the Participant knowingly or grossly negligently failed to prevent the misconduct or (b) the Committee concludes that the Participant engaged in fraud, embezzlement or other similar misconduct materially detrimental to the Corporation.

“Mandatory Retirement” means termination of Employment as a result of the Corporation's policy, if any, requiring the mandatory retirement of officers and/or other employees upon reaching a certain age or milestone.

Exhibit 10.10

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

OFFICER RESTRICTED STOCK AWARD AGREEMENT

with 3 year pro-rata vesting

[GRANT DATE]

Pursuant to this Award Agreement and the Marathon Oil Corporation 2012 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), **[NUMBER]** restricted shares of Common Stock ("Restricted Shares"). The number of Restricted Shares awarded is subject to adjustment as provided in Section 13 of the Plan, and the Restricted Shares are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Restricted Shares is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations, if any, that have been adopted by the Committee. Except as defined in this Award Agreement (including in Sections 9 and 10), capitalized terms shall have the same meanings given to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan.

2. Vesting and Forfeiture of Restricted Shares.

(a) The Restricted Shares shall vest in three cumulative annual installments, as follows:

(i) one-third of the Restricted Shares shall vest on the first anniversary of the Grant Date;

(ii) an additional one-third of the Restricted Shares shall vest on the second anniversary of the Grant Date; and

(iii) all remaining Restricted Shares shall vest on the third anniversary of the Grant Date;

provided, however, that the Participant must be in continuous Employment from the Grant Date through the applicable vesting date for each installment in order for the applicable Restricted Shares to vest on such date. If the Employment of the Participant is terminated for any reason, except as provided in subsection (b) below, any Restricted Shares that have not vested as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) The Restricted Shares shall immediately vest in full, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Participant's Employment due to death;

(ii) termination of the Participant's Employment due to Mandatory Retirement; or

(iii) a Change in Control of the Corporation, provided that as of such Change in Control the Participant has been in continuous Employment since the Grant Date.

3. Issuance of Shares. Effective as of the Grant Date, the Committee or its designated representative shall cause a number of shares of Common Stock equal to the number of Restricted Shares to be issued and registered in the Participant's name, subject to the conditions and restrictions set forth in this Award Agreement and the Plan. Such issuance and registration shall be evidenced by an entry on the registry books of the Corporation and, if the Committee so elects, evidenced by a certificate issued by the Corporation. Any book entries and certificates evidencing the Restricted Shares shall carry or be endorsed with a legend referring to the conditions and restrictions set forth in this Award Agreement and the Plan. In the event the Restricted Shares are evidenced by a certificate, such certificate shall be held in custody by the Corporation unless and until the corresponding Restricted Shares are vested. The Participant shall not be entitled to delivery of a certificate or release of the restrictions on the book entry evidencing such Restricted Shares for any portion of the Restricted Shares unless and until the related Restricted Shares have vested pursuant to Section 2 of this Award Agreement. In the event the Restricted Shares are forfeited in full or in part, the Participant hereby consents to the relinquishment of the forfeited Restricted Shares theretofore issued and registered in the Participant's name to the Corporation at that time.

4. Taxes. Pursuant to Section 10 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise deliverable to the Participant due to the vesting of Restricted Shares pursuant to Section 2 of this Award Agreement, or from other compensation payable to the Participant, at the time of the vesting and delivery of such shares.

5. Shareholder Rights. Unless and until the Restricted Shares are forfeited, the Participant shall have the rights of a shareholder with respect to the Restricted Shares as of the Grant Date, including the right to vote the Restricted Shares and the right to receive dividends. The Participant hereby consents to receiving any dividends on the unvested Restricted Shares through the Corporation's payroll and, accordingly, directs the Corporation's transfer agent to pay such dividends to the Corporation on his or her behalf.

6. Nonassignability. Upon the Participant's death, the Restricted Shares shall be transferred to the Participant's estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Restricted Shares, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Restricted Shares shall have no effect.

7. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary or successor, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

8. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant.

9. Data Privacy. By accepting the Restricted Shares subject to the terms of this Award Agreement, the Participant hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Participant's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Participant's employer, (collectively referred to as "Marathon Oil" in this Section 9) for the exclusive purpose of implementing, administering and managing the Participant's participation in the Plan. The Participant understands and acknowledges that Marathon Oil holds certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Participant's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as "Data" for purposes of this Section 9). The Participant understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Participant's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Participant's country of citizenship or country of residence. The Participant, by acceptance of the Restricted Shares subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Participant's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Participant may elect to deposit the shares following the lapse of applicable restrictions.

10. Definitions. For purposes of this Award Agreement:

"Change in Control," unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“Employment” means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

“Mandatory Retirement” means termination of Employment as a result of the Corporation's policy, if any, requiring the mandatory retirement of officers and/or other employees upon reaching a certain age or milestone.

Exhibit 10.11

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

NONQUALIFIED STOCK OPTION AWARD AGREEMENT

[GRANT DATE]

Non-Officer

Pursuant to this Award Agreement, MARATHON OIL CORPORATION (the “Corporation”) hereby grants to **[NAME]** (the “Optionee”), an employee of the Corporation or a Subsidiary, on **[DATE]** (the “Grant Date”), a right (the “Option”) to purchase from the Corporation **[NUMBER]** shares of Common Stock of the Corporation at a grant price of **$[PRICE]** per share (the “Grant Price”), pursuant to the Marathon Oil Corporation 2012 Incentive Compensation Plan (the “Plan”), with such number of shares and such price per share being subject to adjustment as provided in Section 13 of the Plan, and further subject to the following terms and conditions:

1. **Relationship to the Plan.** This Option is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Sections 12 and 13 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Optionee also include the heirs or other legal representatives of the Optionee.

2. **Exercise and Vesting Schedule.**

(a) This Option shall become exercisable in three cumulative annual installments, as follows:

(i) one-third of the Option Shares shall become exercisable on the first anniversary of the Grant Date;

(ii) an additional one-third of the Option Shares shall become exercisable on the second anniversary of the Grant Date; and

(iii) the remaining one-third of the Option Shares shall become exercisable on the third anniversary of the Grant Date;

provided, however, that the Optionee must be in continuous Employment from the Grant Date through the date of exercisability of each installment in order for the Option to become exercisable with respect to additional shares of Common Stock on such date. If the Employment of the Optionee is terminated for any reason other than death, any Option Shares that are not exercisable as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) This Option shall become fully exercisable, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Optionee's Employment due to death; or

(ii) a Change in Control of the Corporation, provided that as of such Change in Control the Optionee had been in continuous Employment since the Grant Date.

3. Expiration of Option.

(a) Expiration of Option Period. The Option Period shall expire on the tenth anniversary of the Grant Date.

(b) Termination of Employment Due to Death or Retirement. If Employment of the Optionee is terminated due to death or Retirement, the Option shall expire upon the earlier of (i) three years following the date of termination of Employment or (ii) expiration of the Option Period. The death of the Optionee following Retirement but prior to the expiration of the Option shall have no effect on the expiration of the Option.

(c) Termination of Employment by the Corporation for Cause or Due to Resignation. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for Cause or due to voluntary resignation by the Optionee, the Option shall expire upon the termination of Employment.

(d) Termination of Employment by the Corporation Other Than For Cause. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for any reason other than Cause, the Option shall expire upon the earlier of (i) 90 days following the date of termination of Employment or (ii) expiration of the Option Period.

(e) Termination of Employment Following or in Connection with a Change in Control. If Employment of the Optionee is terminated following a Change in Control or in connection with a Change in Control and, as a result, the Optionee is eligible for severance benefits under a Change in Control Plan, the Option shall expire upon the earlier of (i) three years following the date of termination of Employment or (ii) expiration of the Option Period.

4. Employment with a Competitor. Notwithstanding anything herein to the contrary, in the event the Committee, the Chief Executive Officer, or an authorized officer determines that the Optionee has accepted or intends to accept employment with a competitor of any business unit of the Corporation, the Committee, the Chief Executive Officer, or the authorized officer may cancel the Option by written notice to the Optionee.

5. Exercise of Option. Subject to the limitations set forth herein and in the Plan, this Option may be exercised in whole or in part by providing notice to the Committee or its designated representative of the number of Option Shares to be exercised. Such notice shall be accompanied by payment of the Grant Price of such Option Shares in cash or, at the election of the Optionee, in shares of Common Stock or any combination thereof. For purposes of determining the amount, if any, of the purchase price satisfied by payment in Common Stock, such Common Stock shall be valued at its Fair Market Value on the date of exercise. Upon receipt of the purchase price, the Corporation or its designated representative shall issue or cause to be issued to the Optionee a number of shares of Common Stock equal to the number of Option Shares then exercised.

6. Taxes. The Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise payable to the Optionee upon exercise of the Option or from compensation otherwise payable to the Optionee at the time of exercise pursuant to Section 10 of the Plan.

7. Shareholder Rights. The Optionee shall have no rights of a shareholder with respect to the Option Shares unless and until such time as the Option has been exercised and shares of Common Stock have been issued to the Optionee in conjunction with the exercise of the Option.

8. Nonassignability. During the Optionee's lifetime, the Option may be exercised only by the Optionee or by the Optionee's guardian or legal representative. Upon the Optionee's death, the Option shall be transferred to the Optionee's estate.

Otherwise, the Optionee may not sell, transfer, assign, pledge or otherwise encumber any portion of the Option, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Option shall have no effect.

9. No Employment Guaranteed. Nothing in this Award Agreement shall give the Optionee any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Optionee.

10. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Optionee, adversely affect the rights of the Optionee hereunder.

11. Nature of the Grant. In signing this Award Agreement, the Optionee acknowledges that:

(a) the grant of Stock Options is voluntary and occasional and does not create any contractual or other right to receive future awards of Stock Options, or benefits in lieu of Stock Options even if Stock Options have been awarded repeatedly in the past; and

(b) Stock Options are not part of normal or expected compensation or salary for any purpose, including, but not limited to, calculation of any severance, resignation, termination, redundancy, end of service payments, bonuses, long-service awards, pension or retirement benefits or similar payments and in no event should be considered as compensation for, or relating in any way to, past services for the Corporation or its Subsidiaries.

12. Data Privacy. By accepting the Option subject to the terms of this Award Agreement, the Optionee hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Optionee's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Optionee's employer, (collectively referred to as “Marathon Oil” in this Section 12) for the exclusive purpose of implementing, administering and managing the Optionee's participation in the Plan. The Optionee understands and acknowledges that Marathon Oil holds certain personal information about the Optionee, including, but not limited to, the Optionee's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Optionee's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as “Data” for purposes of this Section 12). The Optionee understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Optionee's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Optionee's country of citizenship or country of residence. The Optionee, by acceptance of the Option subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Optionee's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Optionee may elect to deposit any shares of stock acquired upon exercise or settlement of the grant.

13. Definitions. For purposes of this Award Agreement:

“Cause” means termination from Employment by the Corporation or its Subsidiaries due to unacceptable performance, gross misconduct, gross negligence, material dishonesty, material acts detrimental or destructive to the Corporation or its Subsidiaries, employees or property, or any material violation of the policies of the Corporation or its Subsidiaries.

“Change in Control,” unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a “Person”) is or becomes the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term “Person” shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an “Excluded Transaction”) which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“Change in Control Plan” means the Marathon Oil Company Change in Control Severance Benefit Plan or any similar plan, program, agreement, or arrangement under which the Corporation or a Subsidiary agrees to provide benefits to the Optionee in the event he or she is terminated following a Change in Control or in connection with a Change in Control, as applicable to the Optionee at the relevant time.

“Employment” means employment with the Corporation or any of its Subsidiaries. The length of any period of Employment shall be determined by the Corporation or the Subsidiary that either (i) employs the Optionee or (ii) employed the Optionee immediately prior to the Optionee's termination of employment.

“Option Period” means the period commencing upon the Optionee's receipt of this Award Agreement and ending on the date on which the Option expires pursuant to Section 3.

“Option Shares” means the shares of Common Stock covered by this Option.

Exhibit 10.12

Canada

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

NONQUALIFIED STOCK OPTION AWARD AGREEMENT

[GRANT DATE]

Non-Officer

Pursuant to this Award Agreement, MARATHON OIL CORPORATION (the "Corporation") hereby grants to **[NAME]** (the "Optionee"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), a right (the "Option") to purchase from the Corporation **[NUMBER]** shares of Common Stock of the Corporation at a grant price of **$[PRICE]** per share (the "Grant Price"), pursuant to the Marathon Oil Corporation 2012 Incentive Compensation Plan (the "Plan"), with such number of shares and such price per share being subject to adjustment as provided in Section 13 of the Plan, and further subject to the following terms and conditions:

1. **Relationship to the Plan.** This Option is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Sections 12 and 13 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Optionee also include the heirs or other legal representatives of the Optionee.

2. **Exercise and Vesting Schedule.**

(a) This Option shall become exercisable in three cumulative annual installments, as follows:

(i) one-third of the Option Shares shall become exercisable on the first anniversary of the Grant Date;

(ii) an additional one-third of the Option Shares shall become exercisable on the second anniversary of the Grant Date; and

(iii) the remaining one-third of the Option Shares shall become exercisable on the third anniversary of the Grant Date;

provided, however, that the Optionee must be in continuous Employment from the Grant Date through the date of exercisability of each installment in order for the Option to become exercisable with respect to additional shares of Common Stock on such date. If the Employment of the Optionee is terminated for any reason other than death, any Option Shares that are not exercisable as of the date of such termination of Employment shall expire as of such date.

(b) This Option shall become fully exercisable, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Optionee's Employment due to death; or

(ii) a Change in Control of the Corporation, provided that as of such Change in Control the Optionee had been in continuous Employment since the Grant Date.

3. Expiration of Option.

(a) Expiration of Option Period. The Option Period shall expire on the tenth anniversary of the Grant Date.

(b) Termination of Employment Due to Death or Retirement. If Employment of the Optionee is terminated due to death or Retirement, the exercisable portion of the Option shall expire upon the earlier of (i) three years following the date of termination of Employment or (ii) expiration of the Option Period. The death of the Optionee following Retirement but prior to the expiration of the Option shall have no effect on the expiration of the Option.

(c) Termination of Employment by the Corporation for Cause or Due to Resignation. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for Cause or due to voluntary resignation by the Optionee, the Option shall expire upon the termination of Employment.

(d) Termination of Employment by the Corporation Other Than For Cause. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for any reason other than Cause, the exercisable portion of the Option shall expire upon the earlier of (i) 90 days following the date of termination of Employment or (ii) expiration of the Option Period.

(e) Termination of Employment Following Change in Control. If Employment of the Optionee is terminated following a Change in Control and, as a result, the Optionee is eligible for severance benefits under a Change in Control Plan, the Option shall expire upon the earlier of (i) three years following the date of termination of Employment or (ii) expiration of the Option Period.

4. Employment with a Competitor. Notwithstanding anything herein to the contrary, in the event the Committee, the Chief Executive Officer, or an authorized officer determines that the Optionee has accepted or intends to accept employment with a competitor of any business unit of the Corporation, the Committee, the Chief Executive Officer, or the authorized officer may cancel the Option by written notice to the Optionee.

5. Exercise of Option. Subject to the limitations set forth herein and in the Plan, this Option may be exercised in whole or in part by providing notice to the Committee or its designated representative of the number of Option Shares to be exercised. Such notice shall be accompanied by payment of the Grant Price of such Option Shares in cash or, provided that the Optionee is not subject to taxation in Canada with respect to this Option, at the election of the Optionee, in shares of Common Stock or any combination thereof. For purposes of determining the amount, if any, of the purchase price satisfied by payment in Common Stock, such Common Stock shall be valued at its Fair Market Value on the date of exercise. Upon receipt of the purchase price, the Corporation or its designated representative shall issue or cause to be issued to the Optionee a number of shares of Common Stock equal to the number of Option Shares then exercised.

6. Taxes. The Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise payable to the Optionee upon exercise of the Option or from compensation otherwise payable to the Optionee at the time of exercise pursuant to Section 13 of the Plan.

7. Shareholder Rights. The Optionee shall have no rights of a shareholder with respect to the Option Shares unless and until such time as the Option has been exercised and shares of Common Stock have been issued to the Optionee in conjunction with the exercise of the Option.

8. Nonassignability. During the Optionee's lifetime, the Option may be exercised only by the Optionee or by the Optionee's guardian or legal representative. Upon the Optionee's death, the Option shall be transferred to the Optionee's estate. Otherwise, the Optionee may not sell, transfer, assign, pledge or otherwise encumber any portion of the Option, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Option shall have no effect.

9. No Employment Guaranteed. Nothing in this Award Agreement shall give the Optionee any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Optionee.

10. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Optionee, adversely affect the rights of the Optionee hereunder.

11. Nature of the Grant. In signing this Award Agreement, the Optionee acknowledges that:

(a) the grant of Stock Options is voluntary and occasional and does not create any contractual or other right to receive future awards of Stock Options, or benefits in lieu of Stock Options even if Stock Options have been awarded repeatedly in the past; and

(b) Stock Options are not part of normal or expected compensation or salary for any purpose, including, but not limited to, calculation of any severance, resignation, termination, redundancy, end of service payments, bonuses, long-service awards, pension or retirement benefits or similar payments and in no event should be considered as compensation for, or relating in any way to, past services for the Corporation or its Subsidiaries.

12. Data Privacy. By accepting the Option subject to the terms of this Award Agreement, the Optionee hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Optionee's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Optionee's employer, (collectively referred to as “Marathon Oil” in this Section 12) for the exclusive purpose of implementing, administering and managing the Optionee's participation in the Plan. The Optionee understands and acknowledges that Marathon Oil holds certain personal information about the Optionee, including, but not limited to, the Optionee's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Optionee's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as “Data” for purposes of this Section 12). The Optionee understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Optionee's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Optionee's country of citizenship or country of residence. The Optionee, by acceptance of the Option subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Optionee's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Optionee may elect to deposit any shares of stock acquired upon exercise or settlement of the grant.

13. Definitions. For purposes of this Award Agreement:

"Cause" means termination from Employment by the Corporation or its Subsidiaries due to unacceptable performance, gross misconduct, gross negligence, material dishonesty, material acts detrimental or destructive to the Corporation or its Subsidiaries, employees or property, or any material violation of the policies of the Corporation or its Subsidiaries.

"Change in Control," unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

"Change in Control Plan" means the Marathon Oil Company Change in Control Severance Benefit Plan or any similar plan, program, agreement, or arrangement under which the Corporation or a Subsidiary agrees to provide benefits to the Optionee in the event he or she is terminated following a Change in Control, as applicable to the Optionee at the relevant time.

"Employment" means employment with the Corporation or any of its Subsidiaries. The length of any period of Employment shall be determined by the Corporation or the Subsidiary that either (i) employs the Optionee or (ii) employed the Optionee immediately prior to the Optionee's termination of employment.

"Option Period" means the period commencing upon the Optionee's receipt of this Award Agreement and ending on the date on which the Option expires pursuant to Section 3.

"Option Shares" means the shares of Common Stock covered by this Option.

Exhibit 10.13

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

RESTRICTED STOCK AWARD AGREEMENT

with pro-rata vesting

{insert grant date}

Pursuant to this Award Agreement and the Marathon Oil Corporation 2012 Incentive Compensation Plan (the “Plan”), **MARATHON OIL CORPORATION** (the “Corporation”) hereby grants to **[NAME]** (the “Participant”), an employee of the Corporation or an Subsidiary, on **{DATE}** (the “Grant Date”), **[NUMBER]** restricted shares of Common Stock (“Restricted Shares”). The number of Restricted Shares awarded is subject to adjustment as provided in Section 13 of the Plan, and the Restricted Shares are subject to the following terms and conditions:

1. **Relationship to the Plan.** This grant of Restricted Shares is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations, if any, that have been adopted by the Committee. Except as defined in this Award Agreement (including in Sections 9 and 10), capitalized terms shall have the same meanings given to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan.

2. **Vesting and Forfeiture of Restricted Shares.**

(a) The Restricted Shares shall vest in three cumulative annual installments, as follows:

(i) one-third of the Restricted Shares shall vest on the first anniversary of the Grant Date;

(ii) an additional one-third of the Restricted Shares shall vest on the second anniversary of the Grant Date; and

(iii) the remaining one-third of the Restricted Shares shall vest on the third anniversary of the Grant Date;

provided, however, that the Participant must be in continuous Employment from the Grant Date through the applicable vesting date for each installment in order for the applicable Restricted Shares to vest on such date. If the Employment of the Participant is terminated for any reason (including Retirement) other than death, any Restricted Shares that have not vested as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) The Restricted Shares shall vest in full, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Participant's Employment due to death; or

(ii) a Change in Control of the Corporation, provided that as of such Change in Control the Participant had been in continuous Employment since the Grant Date.

3. Issuance of Shares. Effective as of the Grant Date, the Committee or its designated representative shall cause a number of shares of Common Stock equal to the number of Restricted Shares to be issued and registered in the Participant's name, subject to the conditions and restrictions set forth in this Award Agreement and the Plan. Such issuance and registration shall be evidenced by an entry on the registry books of the Corporation and, if the Committee so elects, evidenced by a certificate issued by the Corporation. Any book entries and certificates evidencing the Restricted Shares shall carry or be endorsed with a legend referring to the conditions and restrictions set forth in this Award Agreement and the Plan. In the event the Restricted Shares are evidenced by a certificate, such certificate shall be held in custody by the Corporation unless and until the corresponding Restricted Shares are vested. The Participant shall not be entitled to delivery of a certificate or release of the restrictions on the book entry evidencing such Restricted Shares for any portion of the Restricted Shares unless and until the related Restricted Shares have vested pursuant to Section 2 of this Award Agreement. In the event the Restricted Shares are forfeited in full or in part, the Participant hereby consents to the relinquishment of the forfeited Restricted Shares theretofore issued and registered in the Participant's name to the Corporation at that time.

4. Taxes. Pursuant to Section 10 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise deliverable to the Participant due to the vesting of Restricted Shares pursuant to Section 2 of this Award Agreement, or from other compensation payable to the Participant, at the time of the vesting and delivery of such shares.

5. Shareholder Rights. Unless and until the Restricted Shares are forfeited, the Participant shall have the rights of a shareholder with respect to the Restricted Shares as of the Grant Date, including the right to vote the Restricted Shares and the right to receive dividends. The Participant hereby consents to receiving any dividends on the unvested Restricted Shares through the Corporation's payroll and, accordingly, directs the Corporation's transfer agent to pay such dividends to the Corporation on his or her behalf.

6. Nonassignability. Upon the Participant's death, the Restricted Shares shall be transferred to the Participant's estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Restricted Shares, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Restricted Shares shall have no effect.

7. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary or successor, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

8. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant.

9. Data Privacy. By accepting the Restricted Shares subject to the terms of this Award Agreement, the Participant hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Participant's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Participant's employer, (collectively referred to as "Marathon Oil" in this Section 9) for the exclusive purpose of implementing, administering and managing the Participant's participation in the Plan. The Participant understands and acknowledges that Marathon Oil holds certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Participant's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as "Data" for purposes of this Section 9). The Participant understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Participant's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Participant's country of citizenship or country of residence. The Participant, by acceptance of the Restricted Shares subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Participant's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Participant may elect to deposit the shares following the lapse of applicable restrictions.

10. Definitions. For purposes of this Award Agreement:

"Change in Control," unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

"Employment" means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

Exhibit 10.14

MARATHON OIL CORPORATION

2012 INCENTIVE COMPENSATION PLAN

RESTRICTED STOCK UNIT AWARD AGREEMENT

with 3 year pro-rata vesting

{insert grant date}

Pursuant to this Award Agreement and the Marathon Oil Corporation 2012 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or an Subsidiary, on **{DATE}** (the "Grant Date"), **[NUMBER]** restricted stock units ("Restricted Units") representing the right to receive shares of Common Stock. The number of Restricted Units awarded is subject to adjustment as provided in Section 13 of the Plan, and the Restricted Units are subject to the following terms and conditions:

1. **Relationship to the Plan.** This grant of Restricted Units is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations, if any, that have been adopted by the Committee. Except as defined in this Award Agreement (including in Sections 9 and 11), capitalized terms shall have the same meanings given to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan.

2. **Vesting and Forfeiture of Restricted Units.**

(a) The Restricted Units shall vest in three cumulative annual installments, as follows:

(i) one-third of the Restricted Units shall vest on the first anniversary of the Grant Date;

(ii) an additional one-third of the Restricted Units shall vest on the second anniversary of the Grant Date; and

(iii) all remaining Restricted Units shall vest on the third anniversary of the Grant Date;

provided, however, that the Participant must be in continuous Employment from the Grant Date through the applicable vesting date for each installment in order for the applicable Restricted Units to vest on such date. If the Employment of the Participant is terminated for any reason (including Retirement) other than death, any Restricted Units that have not vested as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) The Restricted Units shall vest in full, irrespective of the limitations set forth in subsection (a) above, upon:

(i) termination of the Participant's Employment due to death; or

(ii) a Change in Control of the Corporation, provided that as of such Change in Control the Participant had been in continuous Employment since the Grant Date.

3. Dividend Equivalents. During the period of time between the Grant Date and the earlier of the date the Restricted Units vest or are forfeited, the Participant shall be entitled to receive dividend equivalent payments from the Corporation on the Restricted Units.

4. Issuance of Shares.

(a) **General Rule.** During the period of time between the Grant Date and the earlier of the date the Restricted Units vest or are forfeited, the Restricted Units will be evidenced by a credit to a bookkeeping account evidencing the unfunded and unsecured right of the Participant to receive shares of Common Stock, subject to the terms and conditions applicable to the Restricted Units. Subject to subsection (b) below, upon the vesting of the Participant's right to receive all or a portion of the Restricted Units pursuant to Section 2 of this Award Agreement, a number of shares of Common Stock equal to the number of vested Restricted Units shall be registered in the name of the Participant and, if requested by the Participant, certificates representing such Common Stock shall be delivered to the Participant. Subject to subsection (b) below, such registration shall occur not later than 75 days after the date on which Restricted Units vest.

(b) **Compliance with Section 409A of the Code.**

(i) Delay of Settlement to Comply with Section 409A. To the extent that immediate settlement of the Restricted Units, which under the terms of this Award Agreement become vested upon a Change in Control, would result in an adverse tax consequence to the Participant under Section 409A of the Code, then the Restricted Units will (subject to subsection (ii) below) be settled upon the earliest to occur of (A) the date on which a change in ownership or change in effective control for purposes of Section 409A of the Code occurs, (B) the date on which the Participant has a Separation from Service or (C) the date on which the restricted stock units would have been settled absent a Change in Control.

(ii) Six Month Delay for Specified Employees. If the Participant is a “specified employee” as determined by the Company in accordance with its established policy, any settlement of restricted stock unit awards, which would be a payment of deferred compensation within the meaning of Section 409A of the Code with respect to the Participant as a result of the Participant's Separation from Service (other than as a result of death) and which would otherwise be paid within six months of the Participant's Separation from Service shall be payable on the date that is one day after the earlier of (A) the date that is six months after the Participant's Separation from Service or (B) the date that otherwise complies with the requirements of Section 409A of the Code.

5. Taxes. Pursuant to Section 10 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise deliverable to the Participant due to the vesting of Restricted Units pursuant to Section 2 of this Award Agreement, or from other compensation payable to the Participant, at the time of the vesting and delivery of such shares.

6. Nonassignability. Upon the Participant's death, the Restricted Units shall be transferred to the Participant's estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Restricted Units, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Restricted Units shall have no effect.

7. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary or successor, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

8. Nature of the Grant. In signing this Award Agreement, the Participant acknowledges that:

(a) the grant of Restricted Units is voluntary and occasional and does not create any contractual or other right to receive future awards of Restricted Units, or benefits in lieu of Restricted Units even if Restricted Units have been awarded repeatedly in the past; and

(b) Restricted Units are not part of normal or expected compensation or salary for any purpose, including, but not limited to, calculation of any severance, resignation, termination, redundancy, end of service payments, bonuses, long-service awards, pension or retirement benefits or similar payments and in no event should be considered as compensation for, or relating in any way to, past services for the Corporation or its Subsidiaries.

9. Data Privacy. By accepting the Restricted Units subject to the terms of this Award Agreement, the Participant hereby explicitly and unambiguously consents to the collection, use and transfer, in electronic or other form, of the Participant's personal data, including but not limited to items of data described in this document, by and among Marathon Oil Corporation and its Subsidiaries and affiliates, including the Participant's employer, (collectively referred to as "Marathon Oil" in this Section 9) for the exclusive purpose of implementing, administering and managing the Participant's participation in the Plan. The Participant understands and acknowledges that Marathon Oil holds certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social insurance number or other identification number, salary, nationality, job title, any shares of stock or directorships held in Marathon Oil, details of all grants or any other entitlement to shares of stock awarded, canceled, forfeited, exercised, vested, unvested or outstanding in the Participant's favor, for the purpose of implementing, administering and managing the Plan (which information is collectively referred to as "Data" for purposes of this Section 9). The Participant understands and agrees that Data may be transferred to any third parties assisting in the implementation, administration and management of the Plan, that these recipients may be located in the Participant's country of citizenship, country of residence or elsewhere, and that the recipient's country may have different data privacy laws and protections than the Participant's country of citizenship or country of residence. The Participant, by acceptance of the Restricted Units subject to the terms of this Award Agreement, authorizes the recipients to receive, possess, use, retain and transfer the Data, in electronic or other form, for the purposes of implementing, administering and managing the Participant's participation in the Plan, including any requisite transfer of such Data as may be required to a broker or other third party with whom the Participant may elect to deposit the shares following the lapse of applicable restrictions.

10. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant.

11. Definitions. For purposes of this Award Agreement:

"Change in Control," unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation's then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the

Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation's assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

"Employment" means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

"Separation from Service," unless otherwise defined by the Committee, shall have the same meaning as set forth under Code section 409A with respect to the Corporation and each related company or business which is part of the same controlled group under Sections 414(b) or 414(c) of the Code; provided that where specified by the Corporation in accordance with Section 409A of the Code in applying Section 1563(a)(1) - (a)(3) of the Code for purposes of determining a controlled group of corporations under Section 414(b) of the Code and in applying Treasury Regulation Section 1.414(c)-2 for purposes of determining whether trades or businesses are under common control under Section 414(c) of the Code, the phrase "at least 50 percent" is used instead of "at least 80 percent."

Exhibit 12.1

Marathon Oil Corporation
Computation of Ratio of Earnings to Fixed Charges
TOTAL ENTERPRISE BASIS - Unaudited

(In millions)

	2012	2011	2010	2009	2008
Portion of rentals representing interest, including discontinued operations	$ 24	$ 51	$ 88	$ 77	$ 89
Capitalized interest, including discontinued operations	68	208	410	441	326
Other interest and fixed charges, including discontinued operations	236	239	105	160	153
Total fixed charges (A)	$ 328	$ 498	$ 603	$ 678	$ 568
Earnings-pretax income with applicable adjustments (B)	$ 6,432	$ 4,707	$ 4,422	$ 3,112	$ 5,181
Ratio of (B) to (A)	19.61	9.45	7.33	4.59	9.12

Exhibit 21.1

Subsidiaries of Marathon Oil Corporation

Company Name	Country	Region
Alaska Transportation Service Company	United States	Delaware
Alba Associates LLC	Cayman Islands	
Alba Equatorial Guinea Partnership, L.P.	United States	Delaware
Alba Plant LLC	Cayman Islands	
Albian Sands Energy Inc.	Canada	
Alchemix Corporation	United States	Arizona
Alvheim AS	Norway	
Amethyst Calypso Pipeline LLC	United States	Delaware
AMPCO Marketing, L.L.C.	United States	Michigan
AMPCO Services, L.L.C.	United States	Michigan
Arctic Sun Shipping Company, Ltd.	United States	Delaware
Atlantic Methanol Associates LLC	Cayman Islands	
Atlantic Methanol Production Company LLC	Cayman Islands	
Beluga Pipe Line Company	United States	Delaware
CIGGS LLC	United States	Delaware
E.G. Global LNG Services, Ltd.	United States	Delaware
Eagle Sun Company Limited	Liberia	
Equatorial Guinea LNG Company, S.A.	Equatorial Guinea	
Equatorial Guinea LNG Holdings Limited	Bahamas	
Equatorial Guinea LNG Operations, S.A.	Equatorial Guinea	
Equatorial Guinea LNG Train 1, S.A.	Equatorial Guinea	
FWA Equipment & Mud Company, Inc.	United States	Delaware
Glacier Drilling Company	United States	Delaware
Globex Energy, Inc.	United States	Delaware
GRT, Inc.	United States	Delaware
GTLI LLC	United States	Delaware
In-Depth Systems, Inc.	United States	Texas
Indonesia Kumawa Energy Limited	Cayman Islands	
Kenai Kachemak Pipeline, LLC	United States	Alaska
Kenai Nikiski Pipeline LLC	United States	Delaware
Marathon Alaska Holding LLC	United States	Delaware
Marathon Alaska Natural Gas Company	United States	Delaware
Marathon Alaska Production LLC	United States	Delaware
Marathon Alpha Holdings LLC	United States	Delaware
Marathon Baja Limited	Cayman Islands	
Marathon Canada Holdings Limited	Canada	Nova Scotia
Marathon Canada Petroleum ULC	Canada	Nova Scotia
Marathon Canada Production ULC	Canada	Alberta
Marathon Canadian Oil Sands Holding Limited	Canada	Alberta
Marathon Delta Holdings Limited	Cayman Islands	
Marathon Delta Investment Limited	Cayman Islands	
Marathon Dutch Investment B.V.	Netherlands	
Marathon Dutch Investment Coöperatief U.A.	Netherlands	
Marathon Dutch Investment LLC	United States	Delaware
Marathon E.G. Alba Limited	Cayman Islands	
Marathon E.G. Holding Limited	Cayman Islands	

Marathon E.G. International Limited	Cayman Islands
Marathon E.G. LNG Holding Limited	Cayman Islands
Marathon E.G. LPG Limited	Cayman Islands

Marathon E.G. Methanol Limited	Cayman Islands	
Marathon E.G. Offshore Limited	Cayman Islands	
Marathon E.G. Oil Operations Limited	Cayman Islands	
Marathon E.G. Production Limited	Cayman Islands	
Marathon Eagle Ford Midstream LLC	United States	Delaware
Marathon East Texas Holdings LLC	United States	Delaware
Marathon Ethiopia Limited B.V.	Netherlands	
Marathon Exploration Tunisia, Ltd.	United States	Delaware
Marathon Financing Trust I	United States	Delaware
Marathon Financing Trust II	United States	Delaware
Marathon Gabon Holding, Ltd.	United States	Delaware
Marathon Global Services, Ltd.	United States	Delaware
Marathon Green B.V.	Netherlands	
Marathon GTF Technology, Ltd.	United States	Delaware
Marathon Indonesia (Bone Bay) Limited	Cayman Islands	
Marathon Indonesia (Kumawa) Limited	Cayman Islands	
Marathon Indonesia Exploration Limited	Cayman Islands	
Marathon Indonesia Holding Limited	Cayman Islands	
Marathon Indonesia New Ventures Limited	Cayman Islands	
Marathon International Oil (G.B.) Limited	United Kingdom	England and Wales
Marathon International Oil Angola Block 31 Limited	Cayman Islands	
Marathon International Oil Angola Block 32 Limited	Cayman Islands	
Marathon International Oil Blanco Limited	Cayman Islands	
Marathon International Oil Canada, Ltd.	United States	Delaware
Marathon International Oil Company	United States	Delaware
Marathon International Oil Holdings LLC	United States	Delaware
Marathon International Oil Libya Limited	Cayman Islands	
Marathon International Oil Morado Limited	Cayman Islands	
Marathon International Oil Portfolio Coöperatief U.A.	Netherlands	
Marathon International Oil Supply Company (G.B.) Limited	United Kingdom	England and Wales
Marathon International Oil Turquesa Limited	Cayman Islands	
Marathon International Oil Ukraine Holding Limited	Cayman Islands	
Marathon International Oil Ventures Limited	Cayman Islands	
Marathon International Petroleum Asia Pacific Limited	Cayman Islands	
Marathon International Petroleum Indonesia Limited	Cayman Islands	
Marathon International Services Limited	Cayman Islands	
Marathon International Upstream, Ltd.	United States	Delaware
Marathon Kenya Limited B.V.	Netherlands	
Marathon LNG Marketing LLC	United States	Delaware
Marathon Methanol Holding LLC	United States	Delaware
Marathon Nigerian Ventures LLC	United States	Delaware
Marathon Norway Investment Coöperatief U.A.	Netherlands	
Marathon Norway Investment LLC	United States	Delaware
Marathon Offshore Alpha Limited	Cayman Islands	
Marathon Offshore Beta Limited	Cayman Islands	
Marathon Offshore Delta Limited	Cayman Islands	
Marathon Offshore Epsilon Limited	Cayman Islands	
Marathon Offshore Investment Limited	Cayman Islands	
Marathon Offshore Libya Service Company, Ltd.	United States	Delaware

Marathon Oil (East Texas) L.P.	United States	Texas
Marathon Oil (Suisse) SA	Switzerland	
Marathon Oil (West Texas) L.P.	United States	Texas
Marathon Oil Canada Corporation	Canada	Alberta

Marathon Oil Cap Bon, Ltd.	United States	Delaware
Marathon Oil Company	United States	Ohio
Marathon Oil Decommissioning Services LLC	United States	Delaware
Marathon Oil Dutch Holdings B.V.	Netherlands	
Marathon Oil Dutch Holdings Coöperatief U.A.	Netherlands	
Marathon Oil Dutch Investment C.V.	Netherlands	
Marathon Oil Eastern, Ltd.	United States	Delaware
Marathon Oil EF II LLC	United States	Delaware
Marathon Oil EF LLC	United States	Delaware
Marathon Oil Exploration (U.K.) Limited	United Kingdom	England and Wales
Marathon Oil Gabon LDC	Cayman Islands	
Marathon Oil Holdings (Barbados) Inc.	Barbados	
Marathon Oil Holdings U.K. Limited	United Kingdom	England and Wales
Marathon Oil International Holding C.V.	Netherlands	
Marathon Oil International LLC	United States	Delaware
Marathon Oil Investment LLC	United States	Delaware
Marathon Oil Jenein Limited	Cayman Islands	
Marathon Oil Jupiter Limited	Cayman Islands	
Marathon Oil KDV B.V.	Netherlands	
Marathon Oil Lapis Limited	Cayman Islands	
Marathon Oil Libya Limited	Cayman Islands	
Marathon Oil Norge AS	Norway	
Marathon Oil North Sea (G.B.) Limited	United Kingdom	England and Wales
Marathon Oil Norway Holdings C.V.	Netherlands	
Marathon Oil Norway Investment LLC	United States	Delaware
Marathon Oil Polska Sp. z o.o.	Poland	
Marathon Oil Preferred Funding, Ltd.	United States	Delaware
Marathon Oil Salmagundi, Ltd.	United States	Delaware
Marathon Oil Sands (U.S.A.) Inc.	United States	Delaware
Marathon Oil Supply Company (U.S.) Limited	United Kingdom	England and Wales
Marathon Oil Switzerland B.V.	Netherlands	
Marathon Oil Timor Gap East, Ltd.	United States	Delaware
Marathon Oil Timor Gap West, Ltd.	United States	Delaware
Marathon Oil U.K. LLC	United States	Delaware
Marathon Oil Upstream, Ltd.	United States	Delaware
Marathon Oil Venus Limited	Cayman Islands	
Marathon Oil West of Shetlands Limited	United Kingdom	England and Wales
Marathon Petroleum Company (Norway) LLC	United States	Delaware
Marathon Portfolio International Limited	Cayman Islands	
Marathon Service (G.B.) Limited	United Kingdom	England and Wales
Marathon Service Company	United States	Delaware
Marathon Upstream Gabon Limited	Cayman Islands	
Marathon Upstream Nigeria Limited	Nigeria	
Marathon Upstream North Sea (G.B.) Limited	United Kingdom	England and Wales
Marathon Upstream U.K. LLC	United States	Delaware
Marathon US Holdings Inc.	United States	Delaware
Marathon West Texas Holdings LLC	United States	Delaware
Marathon Western Saudi Arabia Limited	Cayman Islands	
Miltiades Limited	United Kingdom	England and Wales
MOC Portfolio Delaware, Inc.	United States	Delaware

MP Ukraine Holding Limited	Cyprus	
MWV Gas Gathering, Inc.	United States	Delaware
Navatex Gathering LLC	United States	Delaware

Oil Casualty Insurance, Ltd.	Bermuda	
Old Main Assurance Ltd.	Bermuda	
Palmyra Petroleum Company	Syrian Arab Republic	
Pan Ocean Energy Company	United States	Delaware
Pennaco Energy, Inc.	United States	Delaware
Pheidippides Finance B.V.	Netherlands	
Polar Eagle Shipping Company, Ltd.	United States	Delaware
Red Butte Pipe Line Company	United States	Delaware
SCAL Technology, Inc.	United States	Texas
Seaborn Properties LLC	United States	Delaware
Tarragon Resources (U.S.A.) Inc.	United States	Delaware
Texas Oil & Gas Corp.	United States	Delaware
Vermilion Energy Ireland Limited	Cayman Islands	
Western Bluewater Resources (Trinidad) Limited	Trinidad and Tobago	
Yorktown Assurance Corporation	United States	Vermont

Exhibit 23.1

[PWC Letterhead]

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements listed below of Marathon Oil Corporation of our report dated February 22, 2013 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

On Form S-3ASR:		Relating to:
File No.	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-180014	Dividend Reinvestment and Direct Stock Purchase Plan
On Form S-8:		Relating to:
File No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan
	333-181301	Marathon Oil Corporation 2012 Incentive Compensation Plan

Houston, Texas
February 22, 2013

EXHIBIT 23.2

[Letterhead of GLJ Petroleum Consultants LTD]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERING CONSULTANTS

Re: Marathon Oil Corporation

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation ("the Company"), to our reserve reports relating to the estimated quantities of proved reserves of oil, gas and synthetic crude oil, net to the Company's interest. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-180014	Dividend Reinvestment and Direct Stock Purchase Plan
Form S-8:	Relating to:	
Reg. No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan
	333-181301	Marathon Oil Corporation 2012 Incentive Compensation Plan

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ James H. Willmon, P.Eng.

James H. Willmon, P. Eng.
Vice-President

Calgary, Alberta CANADA
February 22, 2013

EXHIBIT 23.3

[Letterhead of Ryder Scott Company, L.P.]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation ("the Company"), to our summary reports on audits of the estimated quantities of certain proved reserves of oil and gas, net to the Company's interest, and to such report and this consent being filed as exhibits to this Form 10-K. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-180014	Dividend Reinvestment and Direct Stock Purchase Plan
Form S-8:	Relating to:	
Reg. No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan
	333-181301	Marathon Oil Corporation 2012 Incentive Compensation Plan

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 22, 2013

[Ryder Scott Company, L.P. Footer]

EXHIBIT 23.4

[Letterhead of Netherland, Sewell & Associates, Inc.]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation ("the Company"), to our summary report on the estimated quantities of certain proved reserves of oil and gas and to such report and this consent being filed as exhibits to this Form 10-K. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-180014	Dividend Reinvestment and Direct Stock Purchase Plan
Form S-8:	Relating to:	
Reg. No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan
	333-181301	Marathon Oil Corporation 2012 Incentive Compensation Plan

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 22, 2013

Exhibit 31.1

MARATHON OIL CORPORATION

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Clarence P. Cazalot, Jr., certify that:

1. I have reviewed this report on Form 10-K of Marathon Oil Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

February 22, 2013

/s/ Clarence P. Cazalot, Jr.

Clarence P. Cazalot, Jr.
Chairman, President and Chief Executive Officer

Exhibit 31.2

MARATHON OIL CORPORATION

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Janet F. Clark, certify that:

1. I have reviewed this report on Form 10-K of Marathon Oil Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 22, 2013

/s/ Janet F. Clark

Janet F. Clark
Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Marathon Oil Corporation (the "Company") on Form 10-K for the period ending December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Clarence P. Cazalot, Jr., Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

February 22, 2013

/s/ Clarence P. Cazalot, Jr.

Clarence P. Cazalot, Jr.
Chairman, President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Marathon Oil Corporation (the “Company”) on Form 10-K for the period ending December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Janet F. Clark, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

February 22, 2013

/s/ Janet F. Clark

Janet F. Clark
Executive Vice President and Chief Financial Officer

Exhibit 99.1

January 28 2013

Project 1121679

The Board of Directors of Marathon Oil Corporation
Marathon Oil Corporation
2400, 440 - 2nd Avenue SW
Calgary, AB T2P 5E9

Dear Board Members:

Re: <u>Third Party Report on Reserves</u>

This report was prepared to satisfy requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K and to provide the qualifications of the technical persons responsible for overseeing the reserve estimation process.

The numbering of items below corresponds to the requirements set out in Item 1202(a)(8) of Regulation S-K. Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

i. We have prepared an independent evaluation of the Canadian mineable oil sands reserves of Marathon Oil Corporation (the "Company") for the management and the board of directors of the Company. The primary purpose of our evaluation report was to provide estimates of reserves information in support of the Company's year-end reserves reporting requirements under US Securities Regulation S-K and for other internal business and financial needs of the Company.

ii. We have evaluated and reviewed certain reserves of the Company as at December 31, 2012. The completion (transmittal) date of our report is January 28, 2013.

iii. The following table sets forth the total proved net after royalty reserves under constant prices and costs covered by our report by geographic area, and the proportion of the Company covered.

Location	Oil and NGL MMbbl	Natural Gas Bcf	Synthetic Crude Oil[1] MMbbl	Oil Equivalent[2] MMbbl
Canada			653	653
Total Company Reserves[3]	901	2,779	653	2,017
Portion of Total Covered	—%	—%	100%	32%

Notes 1) Total sales less blendstocks, after upgrading AOSP mined bitumen.

2) Oil equivalence factors: Crude Oil, NGL & SCO 1 bbl/bbl, Natural Gas 6 Mcf/bbl

3) Supplied by the company to derive portion of total covered by GLJ

The Company provided to us the total Company reported reserves to derive the portion evaluated by GLJ. We express no opinion on this portion of the Company's reserves that we did not evaluate.

iv. Our report covered 100 percent of the Company's mineable, synthetic crude oil (SCO) reserves; our evaluation coverage from the perspective of the Company's total reserves is provided above in item iii. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the “FASB Standards”) and the legal requirements under the U.S. Securities and Exchange Commission (“SEC requirements”).

The royalty obligations on the evaluated oil sands property, the Athabasca Oil Sands Project (AOSP), are determined upstream, on a bitumen basis. There are two royalty projects, one for Muskeg River Mine operations and one for Jackpine Mine operations. The synthetic crude oil (SCO) reserves reflect both the upgrading yield on bitumen and product value differences between SCO and bitumen. As a consequence of differences in revenue, the royalty rate for SCO is lower than it is on bitumen. No reserves are attributed to internally produced products that are consumed as fuel.

The economic evaluation was prepared to reflect the net present value of Marathon Oil Canada Corporation (MOCC) before any incremental US taxes or overhead. Canadian income taxes were included, as well as MOCC supplied estimates of Calgary Office overhead and abandonment and reclamation obligations.

Data used in our evaluation were obtained from regulatory agencies, public sources and from Company personnel and Company files. In the preparation of our report we have accepted as presented, and have relied, without independent verification, upon a variety of information furnished by the Company such as interests and burdens, recent production, product transportation and marketing and sales agreements, historical revenue, capital costs, operating expense data, budget forecasts, capital cost estimates and well data for recently drilled wells. If in the course of our evaluation, the validity or sufficiency of any material information was brought into question, we did not rely on such information until such concerns were satisfactorily resolved.

The Company has warranted in a representation letter to us that, to the best of the Company's knowledge and belief, all data furnished to us was accurate in all material respects, and no material data relevant to our evaluation was omitted.

A field examination of the evaluated property was not performed nor was it considered necessary for the purposes of our report.

In our opinion, estimates provided in our report have, in all material respects, been determined in accordance with the applicable industry standards, and results provided in our report and summarized herein are appropriate for inclusion in filings under Regulation S-K.

v. As required under SEC Regulation S-K, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. As specified, in determining economic production, constant product reference prices have been based on a 12 month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12 month period prior to the effective date of our report. In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections.

vi. Our report has been prepared assuming the continuation of existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that the Company currently has regulatory approval to produce the reserves identified in our report, there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact the Company's ability to recovery the estimated reserves.

vii. Oil and gas reserves estimates have an inherent degree of associated uncertainty, the degree of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, and contractual, statutory and regulatory provisions.

viii. In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all appropriate industry standards, methods and procedures applicable for the filing of reserves information under U.S. SEC Regulation S-K.

ix. A summary of the Company reserves evaluated by us was provided for item iii. All of the reserves evaluated by us are developed.

GLJ is a private firm established in 1972 whose business is the provision of independent geological and engineering services to the petroleum industry. GLJ is among the largest evaluation firms in North America with approximately 70 professional engineering and geoscience personnel. GLJ evaluate the reserves of the four producing oil sands mining operations for various owners. Mr. Willmon and Mr. Freeborn conducted the evaluation. Both individuals are qualified, independent reserves evaluators as defined in COGEH, and are registered Practicing Professional Engineers in the Province of Alberta. Mr. Willmon has in excess of 33 years of practical experience in petroleum engineering, has been employed at GLJ as an evaluator/auditor since 1982, and has been involved in evaluations of surface mineable oil sands reserves since 1986. Mr. Freeborn has in excess of 12 years of practical experience in petroleum engineering, and has been employed at GLJ as an evaluator/auditor since 1999, and has been involved in evaluations of surface mineable oil sands reserves since 2009.

We trust this meets your current requirements.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"ORIGINALLY SIGNED BY"

Tim R. Freeborn, P. Eng.

"ORIGINALLY SIGNED BY"

James H Willmon, P. Eng.
Vice President

TRF/JHW/ljn

[NSAI Company Logo]

January 29, 2013 **Exhibit 99.4**

Marathon Oil Corporation
5555 San Felipe Road
Houston, Texas 77056

Ladies and Gentlemen:

In accordance with your request, we have prepared a reserves certification and deliverability analysis, as of December 31, 2011, of Alba Field, located offshore Equatorial Guinea. Pursuant to the terms of the Gas Purchase and Sales Agreement (GPSA) between the Alba Field Production Sharing Contract (PSC) contractors (referred to herein as the "Alba Field owners") and Atlantic Methanol Production Company (AMPCO), the primary purpose of this report is to verify, using field downtime and gas disposition assumptions specified by Marathon Oil Corporation (Marathon), that there are (1) sufficient proved (1P) reserves in Alba Field to cover delivery of gas from the Alba Field owners to AMPCO equal to 100 percent of the stated maximum daily quantities over the remaining term of the GPSA that ends May 3, 2026, and (2) sufficient proved developed (PD) reserves in Alba Field to deliver, for a period of five years, 102 percent of the maximum daily contract quantity. The maximum daily contract quantity stipulated in the most recent amendment to the GPSA is 145,000 MMBTU per day, but the annual average daily contract quantity shall not exceed 135,000 MMBTU per day, or approximately 139 million cubic feet of gas per day (MMCFD). For the purposes of this report, we consider the maximum daily contract quantity to be 135,000 MMBTU. Economic analysis was performed only to confirm economic producibility and determine economic limits for the properties. Monetary values shown in this report are expressed in United States dollars ($). For each reserves category, the economic life of the field is either the economic limit or the end of the GPSA, May 3, 2026, whichever is earliest.

We completed our evaluation on April 12, 2012. It is our understanding that Marathon's share of the gross (100 percent) proved reserves estimated in this report constituted approximately 21 percent of all proved reserves owned by Marathon, as of December 31, 2011. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Marathon's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose, provided that, as required by the SEC, Marathon lists its net interest after application of the PSC terms.

Primary condensate separation for Alba Field occurs offshore. The condensate and remaining gas streams are sent to onshore processing facilities at Punta Europa where the condensate is stabilized, liquefied petroleum gas (LPG) is extracted from the gas stream in the LPG plant, and remaining gas is sent to both the methanol and liquefied natural gas (LNG) plants, with excess gas reinjected offshore. In 2007, the LNG plant was commissioned and Marathon ramped up gas sales to the plant while reducing gas injection rates. In 2010, a dehydration modification project was completed onshore in Plant 3, which increased the gas throughput capacity of all onshore facilities combined to 970 MMCFD. During 2011, sales to the methanol plant averaged 127 MMCFD and feedstock sales to the LNG plant averaged 661 MMCFD. In 2011, average production from the 14 producing Alba Field wells was 932 MMCFD, with associated condensate, and approximately 26 MMCFD was reinjected offshore.

We estimate the gross (100 percent) reserves in Alba Field, as of December 31, 2011, to be:

	Gross (100 Percent) Reserves		
Category	Gas (BCF)	Condensate (MMBBL)	LPG (MMBBL)

Proved Developed (PD)	2,186	99	49
Proved (1P)	2,964	131	68

Gas volumes are dry gas and are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Condensate and LPG volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons.

The estimates shown in this report are for proved developed producing and proved undeveloped reserves. Our study indicates that there are no proved developed non-producing reserves for these properties at this time. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of proved undeveloped reserves included in this report are dependent on the conversion of a 16-inch gas injection pipeline to production in 2012 and installation of an offshore compression platform in 2016. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk. In this report, we have attributed estimated gas sales volumes and LPG reserves to Alba Field, even though the LPG plant is separate from the field facilities. This designation is based on our interpretation of the agreement between the Alba Field owners and the LPG plant owners that states that title to the feedstock gas sales volumes and LPG liquids is transferred from the Alba Field owners at the tailgate of the LPG plant and that those volumes are valued on an MMBTU basis. It is our understanding that this interpretation is consistent with Marathon's internal reserves booking practice for Alba Field.

In order to satisfy the primary objective of this report, we made certain assumptions regarding future field production and injection rates. The most significant assumption pertains to the feed rate of Alba Field gas to the LNG plant. Three LNG plant feed scenarios have been considered: a low-take case, a mid-take case, and a high-take case. The LNG plant low-take case is 560 MMCFD, the mid-take case ranges from 595 to 600 MMCFD, and the high-take case ranges from 595 to 640 MMCFD. The high-take case LNG plant feed volumes are based on Marathon's current projection of volumes to be utilized over the next five years. The estimates of reserves shown in this report are based on the high-take case because this case is the most representative of current operating conditions. For the purposes of this report, we define the period during which all forecasted supply targets can be met to be the supply plateau period.

For all cases presented in this report, following the end of the supply plateau period we have reduced supply to the LNG plant prior to reducing supply to the AMPCO methanol plant. Our estimates are based on annual gas rate constraints and annual downtime averages and do not account for any operational or contractual issues that may arise on a day-to-day basis throughout the year. For all three LNG plant feed scenarios, we have determined that there are (1) sufficient 1P reserves to supply the AMPCO methanol plant until termination of the GPSA and (2) sufficient PD reserves to supply the AMPCO methanol plant with 102 percent of the maximum daily contract quantity for a period of five years.

For our study, we had access to certain data and analyses provided by Marathon that were initially presented to us in various reviews and meetings held from June through September 2003. We have received updated data on an annual basis for the purposes of performing an audit of Alba Field reserves on behalf of Noble Energy, Inc. We have also received periodic updates on development plans and the latest analysis done by Marathon. Most recently, this update consisted of a review held in January 2012, where Marathon presented its most recent outlook for Alba. The information and data received to date include, but are not limited to, a geological and geophysical review of Marathon's interpretation of the Alba Field area, limited structure and amplitude maps, formation test results and fluid gradient analysis, petrophysical methodology, fluid property analysis methodology, and potential future development plans. We were provided a digital backup of a Landmark OpenWorks project (3-D seismic data), multiple interpreted seismic horizons, routine and special core analysis data, pressure data, fluid and laboratory analysis reports and subsequent fluid property analysis, digital log data, capillary pressure data, and historical production data.

Our study is an update of previous work that consisted of (1) a geophysical and geological review of the Alba Reservoir; (2) a review of structure and generation of gross isopach maps; (3) a petrophysical analysis of net hydrocarbon pay, porosity, and connate water saturation; (4) a review of pressure and temperature properties as well as fluid properties using existing fluid laboratory analysis and black oil correlations; (5) the generation of proved estimates of wet gas-in-place, dry gas-in-place, condensate-in-place, and LPG-in-place; (6) a reservoir simulation to derive estimates of dry gas, condensate, and LPG recoveries; (7) a review of contractual sales and deliverability obligations for Alba Field, the Alba LPG plant, the LNG plant, and the methanol plant; (8) the generation of production profiles for primary and secondary condensate, LPG, offshore and onshore fuel and flare gas, gas used by the LPG and methanol plants, and remaining gas available for the LNG plant; and (9) a review of economic terms of the Alba PSC and LPG plant contracts. For this study, we have incorporated new production and pressure data into the simulation history matching process and the latest development plans into the simulation prediction cases.

Gas, condensate, and LPG prices were used only to confirm economic producibility and determine economic limits for the properties. The gas price used is the fixed contract price of $0.25 per MMBTU and is adjusted for energy content. Condensate and LPG prices are based on the 12-month unweighted arithmetic average of the first-day-of-the-month Dated Brent spot price for each month in the period January through December 2011. The average price of $109.42 per barrel is adjusted for quality and a regional price differential. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $0.230 per MCF of gas, $108.85 per barrel of condensate, and $70.85 per barrel of LPG.

Operating costs and capital costs were used only to confirm economic producibility and determine economic limits for the properties. Operating costs used in this report are based on operating expense records of Marathon, the operator of the properties. As requested, operating costs are limited to direct platform-, plant-, and field-level costs and Marathon's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Capital costs used in this report were provided by Marathon and are based on its internal budgets. Capital costs are included as required for workovers, a pipeline conversion, installation of an offshore compression platform, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Operating costs are held constant throughout the lives of the properties, and capital costs are held constant to the date of expenditure.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts used to confirm economic producibility and determine economic limits for the properties. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Marathon and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. The contractual rights to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III

By:

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

	/s/ John R. Cliver	/s/ Patrick L. Higgs
By:	By:	
	John R. Cliver, P.E. 107216 Petroleum Engineer	Patrick L. Higgs, P.G. 985 Vice President

Date Signed: January 29, 2013　　Date Signed: January 29, 2013

JRC:JLM

[NSAI Company Logo]

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

- (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
- (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
- (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
  - *(1)* Lifting the oil and gas to the surface; and
  - *(2)* Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
- (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

- a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
- b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

- (A) Transporting, refining, or marketing oil and gas;
- (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
- (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
- (D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas 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-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, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price 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, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability

that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

[NSAI Company Logo]

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects - such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations - by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);

The company's historical record at completing development of comparable long-term projects;

The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;

The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.6

MARATHON OIL CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests
and
Derived Through Certain Production Sharing Contracts

SEC Parameters

As of

December 31, 2011

Jeffrey D. Wilson

Jeffery D. Wilson, P.E.
TBPE License No. 86426
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.

[Ryder Scott Company Logo]

January 24, 2013

Marathon Oil Corporation
5555 San Felipe
P.O. Box 3128
Houston, TX 77253-3128

Gentlemen:

At the request of Marathon Oil Corporation (Marathon), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2011 prepared by Marathon's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on January 8, 2013 and presented herein, was prepared for public disclosure by Marathon in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Marathon's estimated net reserves attributable to the leasehold interests and derived through certain production sharing contracts in certain properties owned by Marathon and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2011. The properties reviewed by Ryder Scott incorporate Marathon reserve determinations and are located in the states of Oklahoma and Texas and in offshore Angola.

The properties reviewed by Ryder Scott account for a portion of Marathon's total net proved reserves as of December 31, 2011. Based on the estimates of total net proved reserves prepared by Marathon, the reserves audit conducted by Ryder Scott addresses 2 percent of the total proved developed net liquid hydrocarbon reserves, 2 percent of the total proved developed net gas reserves, 42 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 26 percent of the total proved undeveloped net gas reserves of Marathon.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as “the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities.”

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2011 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Marathon has informed us that in the preparation of their reserve and income projections, as of December 31, 2011, they used average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Marathon attributable to Marathon's interest in properties that we reviewed are summarized as follows:

SEC PARAMETERS
Estimated Net Reserves
Attributable to Certain Leasehold Interests and
Derived Through Certain Production Sharing Contracts of
Marathon Oil Corporation

As of December 31, 2011

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves of Properties <u>Audited by Ryder Scott</u>			
Oil/Condensate - MBarrels	11,484	79,807	91,291
Plant Products - MBarrels	5,103	25,751	30,854
Gas - MMCF	42,964	229,032	271,996
MMBOE	23,748	143,730	167,478

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels (MBarrels). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MMBOE means million barrels of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “Petroleum Reserves Definitions” is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled “Petroleum Reserves Status Definitions and Guidelines” in this report. The proved reserves included herein consist of the developed and undeveloped categories.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Marathon's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

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.” The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.”

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely than not to be achieved.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated primarily by performance-based methods and analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve and other production analysis. These analyses utilized extrapolations of historical production data available through December 2011 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Marathon or obtained from public data sources and were considered sufficient for the purpose thereof.

The undeveloped reserves in Angola were estimated by volumetrics. The remaining proved developed (non-producing) and undeveloped reserves included herein were estimated by analogy to the historical performance of mature areas within each unit or field where these analogues were applied. These estimates were also verified with volumetrics as a secondary method. Data was furnished to Ryder Scott by Marathon or obtained from public data sources that were available through December 2011. The data utilized from the analogues as well as the seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

The fields located in Oklahoma and Texas are oil shales and are developed almost entirely using horizontal drilling technology.

To estimate economically recoverable proved oil and gas reserves, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Marathon relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Marathon for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2011 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by Marathon for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by Marathon to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon.

The table below summarizes Marathon's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Marathon's “average realized prices.” The average realized prices shown in the table below were determined from Marathon's estimate of the total future gross revenue before production taxes and Marathon's estimate of the total net reserves for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Price Reference	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$96.19/Bbl	$100.78/Bbl
	NGL	Mont Belvieu	$60.61/Bbl	$42.59/Bbl
	Gas	Henry Hub	$2.76/MCF	$4.04/MCF
Angola	Oil/Condensate	Brent	$111.04/Bbl	$102.16/Bbl
	Gas	Not Sold	NA	NA

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Marathon's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Operating costs furnished by Marathon are based on the operating expense reports of Marathon and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Where applicable operating costs were included for transportation, tariffs and/or processing fees. The operating costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Marathon are based on authorizations for expenditure for the proposed work or actual costs for similar projects. For the Angola properties, the development costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon.

The proved developed (non-producing) and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Marathon's plans to develop these reserves as of December 31, 2011. The implementation of Marathon's development plans as presented to us is subject to the approval process adopted by Marathon's management. As the result of our inquiries during the course of our review, Marathon has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Marathon's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Marathon. Additionally, Marathon has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by Marathon were held constant throughout the life of the properties.

The net reserves for the Angola properties are derived through a Production Sharing Contract, and as such are directly impacted by the cost and price assumptions applied herein. The Production Sharing Contract terms were supplied by Marathon and accepted as factual data and reviewed for their reasonableness. We have not conducted a detailed review of the contract or Marathon's interpretation and/or application of the contract terms.

Marathon's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Marathon to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Marathon. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Marathon's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to,

reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal right to produce or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain. Furthermore, properties in the different countries may be subjected to significantly varying contractual fiscal terms that affect the net revenue to Marathon for the production of these volumes. The prices and economic return received for these net volumes can vary significantly based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such contracts and discussed with Marathon the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Marathon's representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Marathon operates or has interests. Marathon's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms of various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Marathon owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Marathon for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Marathon are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Marathon has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Marathon's forecast of future proved production, we have relied upon data furnished by Marathon with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Marathon. We consider the factual data furnished to us by Marathon to be appropriate and sufficient for the purpose of our review of Marathon's estimates of reserves. In summary, we consider

the assumptions, data, methods and analytical procedures used by Marathon and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2011 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

We were in reasonable agreement with Marathon's estimates of proved reserves for the properties which we reviewed. As a consequence, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Marathon.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy-five years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Marathon. Neither we nor any of our employees have any interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Marathon.

Marathon makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Marathon has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Marathon of the references to our name as well as to the references to our third party report for Marathon, which appears in the December 31, 2011 annual report on Form 10-K of Marathon. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Marathon.

We have provided Marathon with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Marathon and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Jeffrey D. Wilson

Jeffrey D. Wilson, P.E.
TBPE License No. 86426
Managing Senior Vice President

[SEAL]

JDW (FPR)/pl

Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Jeffrey D. Wilson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1998, is a Senior Vice President and also serves as a member of the Board of Directors responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Exxon. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Wilson earned a Bachelor of Science degree in Mechanical Engineering from the University of Houston in 1991, graduating with Magna Cum Laude honors, and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and currently serves as a member of the SPE Oil and Gas Reserves Committee.

The Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills. As part of his 2012 continuing education hours, Mr. Wilson attended an internally presented 12 hours of formalized training and 7 hours of formalized external training on various topics including SEC oil and gas reporting requirements, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, overviews of the various productive basins, evaluations of resource play reserves, petroleum economics evaluation methods and software, and ethics training. Mr. Wilson also taught multiple classes throughout the year for a total of 5 hours class time on advanced economic modeling techniques.

Based on his educational background, professional training and more than 20 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits.

These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas 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-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, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price 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, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

> *(i) 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; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) *completion intervals which are open at the time of the estimate, but which have not started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) *Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Income Taxes (Tables)

12 Months Ended
Dec. 31, 2012

Income Taxes Disclosure [Abstract]

Schedule of Components of Income Tax Expense (Benefit)

Income tax provisions (benefits) were:

(In millions)	2012 Current	2012 Deferred	2012 Total	2011 Current	2011 Deferred	2011 Total	2010 Current	2010 Deferred	2010 Total
Federal	$ (80)	$ 233	$ 153	$ (210)	$ (206)	$ (416)	$ (279)	$ (267)	$ (546)
State and local	(23)	47	24	24	82	106	2	(10)	(8)
Foreign	4,844	(490)	4,354	3,088	(58)	3,030	2,941	(212)	2,729
Total	$ 4,741	$ (210)	$4,531	$ 2,902	$ (182)	$2,720	$ 2,664	$ (489)	$2,175

Schedule of Effective Income Tax Rate Reconciliation

A reconciliation of the federal statutory income tax rate applied to income from continuing operations before income taxes to the provision for income taxes follows:

	2012	2011	2010
Statutory rate applied to income from continuing operations before income taxes	35%	35%	35 %
Effects of foreign operations, including foreign tax credits	18	6	20
Change in permanent reinvestment assertion	—	5	—
Adjustments to valuation allowances	21	14	(2)
Tax law changes	—	1	1
Effective income tax rate on continuing operations	74%	61%	54 %

Schedule of Deferred Tax Assets and Liabilities

Deferred tax assets and liabilities resulted from the following:

(In millions)	December 31, 2012	December 31, 2011[(a)]
Deferred tax assets:		
Employee benefits	$ 510	$ 455
Operating loss carryforwards	368	354
Foreign tax credits	4,351	3,005
Other	121	95
Valuation allowances:		
Federal	(2,067)	(790)
State, net of federal benefit	(60)	(40)
Foreign	(210)	(194)
Total deferred tax assets	3,013	2,885
Deferred tax liabilities:		
Property, plant and equipment	3,691	3,404
Investments in subsidiaries and affiliates	840	1,216
Other	12	41
Total deferred tax liabilities	4,543	4,661
Net deferred tax liabilities	$ 1,530	$ 1,776

Net Deferred Tax Assets Liabilities Table

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

(In millions)	December 31, 2012	December 31, 2011

Assets:		
Other current assets	$ 57	$ 99
Other noncurrent assets	849	674
Liabilities:		
Other current liabilities	4	5
Noncurrent deferred tax liabilities	2,432	2,544
Net deferred tax liabilities	$ 1,530	$ 1,776

Income Tax Returns Remaining Subject To Examination Table

As of December 31, 2012, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[a]	2005-2011
Canada	2008-2011
Equatorial Guinea	2007-2011
Libya	2006-2011
Norway	2008-2011
United Kingdom	2008-2011

[a] Includes federal and state jurisdictions.

Summary Of Activity In Unrecognized Tax Benefits Table

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2012	2011	2010
Beginning balance	$ 157	$ 103	$ 75
Additions for tax positions related to the current year	—	4	28
Reductions for tax positions related to the current year	—	—	(1)
Additions for tax positions of prior years	81	87	25
Reductions for tax positions of prior years	(67)	(29)	(12)
Settlements	(72)	(8)	(12)
Statute of limitations	(1)	—	—
Ending balance	$ 98	$ 157	$ 103

Spin-Off (Details) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended			
	Dec. 31, 2011	Dec. 31, 2010	Jun. 30, 2011 independent_energy_company	Jun. 27, 2011
Spin Off Disclosure [Abstract]				
Number of Independent Energy Companies			2	
Number of Common Shares Received of MPC				1
Number of Common Shares of Marathon Stock Owned				2
Discontinued Operations Disclosure [Abstract]				
Revenues applicable to discontinued operations	$ 38,602	$ 62,488		
Pretax income from discontinued operations	$ 2,012	$ 1,065		

Supplemental Cash Flow Information (Tables)	12 Months Ended Dec. 31, 2012
Supplemental Cash Flow Information [Abstract]	
Schedule Of Interest And Income Taxes Paid And Significant Noncash Transactions	

(In millions)	2012	2011	2010
Net cash provided by operating activities included:			
Interest paid (net of amounts capitalized)	$ 225	$ 268	$ 107
Income taxes paid to taxing authorities	4,974	2,893	2,155
Commercial paper:			
Issuances	$ 13,880	$ 421	$ —
Repayments	(13,680)	(421)	—
Net commercial paper	$ 200	$ —	$ —
Noncash investing and financing activities:			
Additions to property, plant and equipment			
Asset retirement costs capitalized, excluding acquisitions	$ 286	$ 151	$ 207
Change in capital expenditure accrual	191	104	(140)
Liabilities assumed in acquisitions	109	126	—
Debt payments made by United States Steel	20	214	105

Equity Method Investments and Related Party Transactions (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Equity Method Investment Balance Sheet Reported Amounts [Abstract]			
Current assets	$ 607	$ 688	
Noncurrent assets	1,743	2,079	
Current liabilities	395	504	
Noncurrent liabilities	29	115	
Equity Method Investment, Difference Between Carrying Amount and Underlying Equity	133		
Proceeds from Equity Method Investment, Dividends or Distributions	381	509	400
Equity Method Investment, Summarized Financial Information, Income Statement [Abstract]			
Revenues and other income	1,330	1,544	1,305
Income from operations	755	942	762
Net income	635	820	671
Schedule of Equity Method Investments [Line Items]			
Equity Method Investments	1,279	1,383	
EG Holdings [Member]			
Schedule of Equity Method Investments [Line Items]			
Equity Method Investment, Ownership Percentage	60.00%		
Equity Method Investments	817	875	
Related Party Sales, Percentage	75.00%		
Alba Plant LLC [Member]			
Schedule of Equity Method Investments [Line Items]			
Equity Method Investment, Ownership Percentage	52.00%		
Equity Method Investments	264	272	
AMPCO [Member]			
Schedule of Equity Method Investments [Line Items]			
Equity Method Investment, Ownership Percentage	45.00%		
Equity Method Investments	187	191	
Other Equity Method Investees [Member]			
Schedule of Equity Method Investments [Line Items]			
Equity Method Investments	$ 11	$ 45	

Variable Interest Entities (Details) (Variable Interest Entity, Not Primary Beneficiary [Member], USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2012
Variable Interest Entity, Not Primary Beneficiary [Member]	
Variable Interest Entity [Line Items]	
Variable Interest Entity, Qualitative or Quantitative Information, Ownership Percentage	20.00%
Recorded liability related to unconsolidated VIE	$ 3
Maximum exposure to loss related to unconsolidated VIE	$ 694

Derivatives (Details-BS) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012	Dec. 31, 2012 Other Current Assets [Member] Not Designated as Hedging Instrument [Member]	Dec. 31, 2012 Commodity [Member] Other Current Assets [Member] Not Designated as Hedging Instrument [Member]	Dec. 31, 2011 Interest rate [Member] Other Noncurrent Assets [Member] Designated as Hedging Instrument [Member]	Dec. 31, 2012 Fair Value Hedging [Member] Designated as Hedging Instrument [Member]	Dec. 31, 2012 Fair Value Hedging [Member] Foreign Exchange Contract [Member] Other Current Assets [Member] Designated as Hedging Instrument [Member]	Dec. 31, 2012 Fair Value Hedging [Member] Interest rate [Member] Other Noncurrent Assets [Member] Designated as Hedging Instrument [Member]
Derivatives Fair Value [Line Items]							
Derivative Asset, Fair Value, Gross Asset	$ 91	$ 52	$ 52		$ 39	$ 18	$ 21
Derivative Asset, Fair Value, Gross Liability	0	0	0		0	0	0
Derivative Asset, Fair Value, Net	$ 91	$ 52	$ 52	$ 5	$ 39	$ 18	$ 21

Debt (Tables)	12 Months Ended Dec. 31, 2012

[Debt Disclosure [Abstract]]

[Debt Instrument Table]

The following table details our long-term debt:

(In millions)	December 31, 2012	December 31, 2011
Senior unsecured notes:		
9.375% notes due 2012	$ —	$ 53
9.125% notes due 2013	114	114
0.900% notes due 2015[a]	1,000	—
6.000% notes due 2017[a]	682	682
5.900% notes due 2018[a]	854	854
7.500% notes due 2019[a]	228	228
2.800% notes due 2022[a]	1,000	—
9.375% notes due 2022	32	32
Series A notes due 2022	3	3
8.500% notes due 2023	70	70
8.125% notes due 2023	131	131
6.800% notes due 2032[a]	550	550
6.600% notes due 2037	750	750
Capital leases:		
Capital lease obligation due 2012	—	9
Sale-leaseback obligation due 2012	—	11
Capital lease obligation of consolidated subsidiary due 2013 – 2049	11	11
Other obligations:		
4.550% promissory note, semi-annual payments due 2013 – 2015	204	272
5.375% obligation relating to revenue bonds due 2013	—	23
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Other	35	—
Total[b]	6,664	4,793
Unamortized discount	(11)	(10)
Fair value adjustments[c]	43	32
Amounts due within one year	(184)	(141)
Total long-term debt due after one year	$ 6,512	$ 4,674

[a] These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

[b] In the event of a change in control, as defined in the related agreements, debt obligations totaling $385 million at December 31, 2012, may be declared immediately due and payable.

[c] See Note 15 for information on interest rate swaps.

[Five Year Schedule Of Debt Payments Table]

The following table shows five years of long-term debt payments:

(In millions)	
2013	$ 184
2014	71
2015	1,070

2016	3
2017	685

Spin-Off (Tables)	12 Months Ended Dec. 31, 2012
Spin Off Disclosure [Abstract]	
Spin Off Discontinued Operations Disclosure	The results of operations of our downstream business have been reported as discontinued operations for 2011 and 2010. The table below shows selected financial information reported in discontinued operations related to the spin-off.

(In millions)	2011	2010
Revenues applicable to discontinued operations	$ 38,602	$ 62,488
Pretax income from discontinued operations	$ 2,012	$ 1,065

Derivatives (Details 2-Interest Rate Hedges)	3 Months Ended Mar. 31, 2011 USD ($)	Dec. 31, 2012 USD ($)	Dec. 31, 2012 NOK	Dec. 31, 2011 USD ($)
Interest Rate Fair Value Hedges [Abstract]				
Notional Amount of Interest Rate Fair Value Hedge Derivatives	$ 1,450,000,000	$ 600,000,000		$ 600,000,000
Weighted-average, LIBOR-based, floating rate		4.70%	4.70%	4.76%
Interest Rate Swaps	29,000,000			
Notional Amount of Foreign Currency Derivatives		$ 5.780	3,043,000,000	

Property, Plant and Equipment (Details 3) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012 project	Dec. 31, 2011	Dec. 31, 2010
Total Deferred Exploratory Well Costs [Abstract]			
Amounts capitalized greater than one year after completion of drilling	$ 229	$ 222	$ 323
Projects that have exploratory wWell costs that have been capitalized for period greater than one year, number of projects suspended	6		
Angola Capitalized Greater One Year [Member]			
Total Deferred Exploratory Well Costs [Abstract]			
Amounts capitalized greater than one year after completion of drilling	128		
Norway Capitalized Greater One Year [Member]			
Total Deferred Exploratory Well Costs [Abstract]			
Amounts capitalized greater than one year after completion of drilling	70		
Other International Capitalized Greater One Year [Member]			
Total Deferred Exploratory Well Costs [Abstract]			
Amounts capitalized greater than one year after completion of drilling	22		
United States Capitalized Greater One Year [Member]			
Total Deferred Exploratory Well Costs [Abstract]			
Amounts capitalized greater than one year after completion of drilling	$ 9		

Defined Benefit Postretirement Plans and Defined Contribution Plan (Details 4) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Defined Benefit Plan, Effect of One-Percentage Point Change in Assumed Health Care Cost Trend Rates [Abstract]			
Defined Benefit Plan, Effect of One Percentage Point Increase on Service and Interest Cost Components	2		
Defined Benefit Plan, Effect of One Percentage Point Decrease on Service and Interest Cost Components	(2)		
Defined Benefit Plan, Effect of One Percentage Point Increase on Accumulated Postretirement Benefit Obligation	35		
Defined Benefit Plan, Effect of One Percentage Point Decrease on Accumulated Postretirement Benefit Obligation	(29)		
Medical Pre-65 [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Health care cost trend rate assumed for the following year:	8.00%	7.50%	7.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:	2020	2018	2018
Medical Post-65 [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Health care cost trend rate assumed for the following year:	7.00%	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:	2018	2017	2017
Assumed Health Care Cost Prescription Drugs [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Health care cost trend rate assumed for the following year:	7.00%	7.50%	7.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:	2018	2018	2018
EGWP subsidy [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Health care cost trend rate assumed for the following year:	7.50% [1]		
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):	5.00% [1]		
Year that the rate reaches the ultimate trend rate:	2020 [1]		
Equity Securities [Member] | United States Pension Plans of US Entity, Defined Benefit [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Defined Benefit Plan, Target Plan Asset Allocations	65.00%		
Equity Securities [Member] | Foreign Pension Plans, Defined Benefit [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Defined Benefit Plan, Target Plan Asset Allocations	70.00%		

Fixed Income Securities [Member] | United States Pension Plans of US Entity, Defined Benefit [Member]	
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]	
Defined Benefit Plan, Target Plan Asset Allocations	35.00%
Fixed Income Securities [Member] | Foreign Pension Plans, Defined Benefit [Member]	
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]	
Defined Benefit Plan, Target Plan Asset Allocations	30.00%

[1] An employee group waiver plan ("EGWP") is a group Medicare Part D prescription drug plan. Effective January 1, 2013, we implemented the EGWP as a result of the Patient Protection and Affordable Care Act, which ended tax-free status of retiree drug subsidy programs but increased federal funding to Part D prescription drug plans.

Acquisitions (Business Comb) (Details) (USD $)	12 Months Ended			0 Months Ended		3 Months Ended	12 Months Ended
	Dec. 31, 2012 acre	Nov. 01, 2012	Aug. 01, 2012	Aug. 01, 2012 Eagle Ford Paloma [Member]	Nov. 01, 2012 Eagle Ford 2012 [Member]	Dec. 31, 2011 Hilcorp Eagle Ford [Member] acre	Dec. 31, 2011 Hilcorp Eagle Ford [Member] acre
Business Acquisition [Line Items]							
Business acquisition discount factor				10.00%			11.00%
Gas and Oil Acreages, Acquired	25,000						
Current assets:							
Cash				$ 8,000,000	$ 0		
Receivables				22,000,000	8,000,000	40,000,000	40,000,000
Inventories				1,000,000	0	4,000,000	4,000,000
Other current assets						30,000,000	30,000,000
Total current assets acquired				31,000,000	8,000,000	74,000,000	74,000,000
Property, plant and equipment				822,000,000	248,000,000	4,501,000,000	4,501,000,000
Other noncurrent assets						21,000,000	21,000,000
Total assets acquired				853,000,000	256,000,000	4,596,000,000	4,596,000,000
Current liabilities:							
Accounts payable				78,000,000	23,000,000	101,000,000	101,000,000
Other current liabilities						20,000,000	20,000,000
Total current liabilities assumed		23,000,000	78,000,000			121,000,000	121,000,000
Asset retirement obligations				7,000,000	1,000,000	5,000,000	5,000,000
Total liabilities assumed				85,000,000	24,000,000	126,000,000	126,000,000
Net assets acquired				768,000,000	232,000,000	4,470,000,000	4,470,000,000
Gas and oil acreages undeveloped and developed net						167,000	167,000
Acquisition Costs, Period Cost						4,500,000,000	
Business Acquisition, Cost of Acquired Entity, Cash Paid				$ 768,000,000	$ 232,000,000		

Fair Value Measurements (Details 2-Nonrecurring) (USD $) In Millions, unless otherwise specified	12 Months Ended				1 Months Ended	3 Months Ended	1 Months Ended	8 Months Ended
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2012 Assets Held and Used Ozona [Member]	Mar. 31, 2010 Assets held and used powder river basin [Member]	Dec. 31, 2012 Assets held and used powder river basin [Member]	May 31, 2011 Assets Held and Used Droshky [Member] Boe	Dec. 31, 2011 Assets Held and Used Droshky [Member]
Fair Value, Assets and Liabilities Measured on Nonrecurring Basis, Financial Statement [Line Items]								
Fair value of long-lived assets held for use, year-to-date	$ 16	$ 226	$ 147	$ 6	$ 144	$ 6		
Impairment of long-lived assets held for use	371	285	447	289	423	73		273
Impairment of Long-Lived Assets to be Disposed of Fair Value	0	0	85					
Impairment of Long-Lived Assets to be Disposed of Impairment	0	0	64					
Fair Value of Intangible Assets, year-to-date	0	0	0					
Impairment of Intangible Assets, Finite-lived	0	25	0					
Equity Method Investments, Fair Value Disclosure	0	0	0					
Equity Method Investment, Other than Temporary Impairment	0	0	25					
Proved reserves write off							3,400,000	
Property Plant And Equipment Related To Quarter Fair Value Disclosure								$ 226

Defined Benefit Postretirement Plans and Defined Contribution Plan (Details) (USD $)	12 Months Ended Dec. 31, 2012	12 Months Ended Dec. 31, 2011
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets [Abstract]		
Accumulated benefit obligation	$ 1,442,000,000	$ 1,231,000,000
United States Pension Plans of US Entity, Defined Benefit [Member]		
Change in benefit obligations:		
Benefit obligations at January 1	986,000,000	3,221,000,000
Spin-off downstream business	0	(2,308,000,000)
Service cost	31,000,000	28,000,000
Interest cost	42,000,000	44,000,000
Plan amendment	0	0
Actuarial loss	196,000,000	84,000,000
Foreign currency exchange rate changes	0	0
Benefits paid	(109,000,000)	(83,000,000)
Benefit obligations at December 31	1,146,000,000	986,000,000
Change in plan assets:		
Fair value of plan assets at January 1	516,000,000	1,798,000,000
Spin-off downstream business	0	(1,268,000,000)
Actual return on plan assets	66,000,000	30,000,000
Employer contributions	157,000,000	39,000,000
Foreign currency exchange rate changes	0	0
Benefits paid	(109,000,000)	(83,000,000)
Fair value of plan assets at December 31	630,000,000	516,000,000
Funded status of plans at December 31		
Funded status of plans at December 31	(516,000,000)	(470,000,000)
Amounts recognized in the consolidated balance sheet:		
Current liabilities	(17,000,000)	(17,000,000)
Noncurrent liabilities	(499,000,000)	(453,000,000)
Accrued benefit cost	(516,000,000)	(470,000,000)
Pretax amounts in accumulated other comprehensive loss:		
Net loss	511,000,000	432,000,000
Prior service cost (credit)	21,000,000	27,000,000
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets [Abstract]		
Projected benefit obligation	(1,146,000,000)	(986,000,000)
Accumulated benefit obligation	(937,000,000)	(813,000,000)
Fair value of plan assets	630,000,000	516,000,000
Foreign Pension Plans, Defined Benefit [Member]		
Change in benefit obligations:		
Benefit obligations at January 1	465,000,000	415,000,000

Spin-off downstream business	0	0
Service cost	19,000,000	19,000,000
Interest cost	22,000,000	22,000,000
Plan amendment	0	11,000,000
Actuarial loss	49,000,000	13,000,000
Foreign currency exchange rate changes	25,000,000	(2,000,000)
Benefits paid	(15,000,000)	(13,000,000)
Benefit obligations at December 31	565,000,000	465,000,000
Change in plan assets:		
Fair value of plan assets at January 1	412,000,000	389,000,000
Spin-off downstream business	0	0
Actual return on plan assets	57,000,000	15,000,000
Employer contributions	24,000,000	23,000,000
Foreign currency exchange rate changes	22,000,000	(2,000,000)
Benefits paid	(15,000,000)	(13,000,000)
Fair value of plan assets at December 31	500,000,000	412,000,000
Funded status of plans at December 31		
Funded status of plans at December 31	(65,000,000)	(53,000,000)
Amounts recognized in the consolidated balance sheet:		
Current liabilities	0	0
Noncurrent liabilities	(65,000,000)	(53,000,000)
Accrued benefit cost	(65,000,000)	(53,000,000)
Pretax amounts in accumulated other comprehensive loss:		
Net loss	74,000,000	63,000,000
Prior service cost (credit)	10,000,000	11,000,000
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets [Abstract]		
Projected benefit obligation	(565,000,000)	(465,000,000)
Accumulated benefit obligation	(505,000,000)	(418,000,000)
Fair value of plan assets	500,000,000	412,000,000
Other Postretirement Benefit Plans, Defined Benefit [Member]		
Change in benefit obligations:		
Benefit obligations at January 1	301,000,000	779,000,000
Spin-off downstream business	0	(483,000,000)
Service cost	4,000,000	4,000,000
Interest cost	14,000,000	16,000,000
Plan amendment	0	0
Actuarial loss	8,000,000	1,000,000
Foreign currency exchange rate changes	0	0
Benefits paid	(16,000,000)	(16,000,000)
Benefit obligations at December 31	311,000,000	301,000,000
Change in plan assets:		
Fair value of plan assets at January 1	0	0
Spin-off downstream business	0	0

Actual return on plan assets	0	0
Employer contributions	0	0
Foreign currency exchange rate changes	0	0
Benefits paid	(16,000,000)	(16,000,000)
Fair value of plan assets at December 31	0	0
Funded status of plans at December 31		
Funded status of plans at December 31	(311,000,000)	(301,000,000)
Amounts recognized in the consolidated balance sheet:		
Current liabilities	(19,000,000)	(18,000,000)
Noncurrent liabilities	(292,000,000)	(283,000,000)
Accrued benefit cost	(311,000,000)	(301,000,000)
Pretax amounts in accumulated other comprehensive loss:		
Net loss	23,000,000	16,000,000
Prior service cost (credit)	$ (11,000,000)	$ (18,000,000)

Derivatives Derivatives (Details 4-Non Hedges Commodity) (Details) (Commodity [Member], USD $) In Millions, unless otherwise specified	5 Months Ended				12 Months Ended				
	Dec. 31, 2012 Not Designated as Hedging Instrument [Member] Swap [Member] West Texas Intermediate [Member]	Dec. 31, 2012 Not Designated as Hedging Instrument [Member] Swap [Member] Brent [Member]	Dec. 31, 2012 Not Designated as Hedging Instrument [Member] Option Collar [Member] West Texas Intermediate [Member]	Dec. 31, 2012 Not Designated as Hedging Instrument [Member] Option Collar [Member] Brent [Member]	Dec. 31, 2012 Not Designated as Hedging Instrument [Member] Sales [Member]	Dec. 31, 2011 Not Designated as Hedging Instrument [Member] Sales [Member]	Dec. 31, 2010 Not Designated as Hedging Instrument [Member] Sales [Member]	Dec. 31, 2012 Not Designated as Hedging Instrument [Member] Option Collar [Member] West Texas Intermediate [Member]	Dec. 31, 2012 Not Designated as Hedging Instrument [Member] Option Collar [Member] Brent [Member]
Exploration and Production Commodity Derivative [Line Items]									
Nonmonetary Notional Amount of Price Risk Derivative Instruments Not Designated as Hedging Instruments	20,000	25,000	15,000	15,000					
Derivative, Swap Type, Average Fixed Price	96.29	109.19							
Derivative, Average Floor Price								90.00	100.00
Derivative, Average Cap Price								101.17	116.30
Derivative Instruments, Gain (Loss) Recognized in Income, Net					$ 70	$ 5	$ 121		

Defined Benefit Postretirement Plans and Defined Contribution Plan (Details 2) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
United States Pension Plans of US Entity, Defined Benefit [Member]			
Components of net periodic benefit cost:			
Service cost	$ 31	$ 28	$ 30
Interest cost	42	44	47
Expected return on plan assets	(43)	(43)	(44)
Depreciation, Depletion and Amortization [Abstract]			
- prior service cost (credit)	7	6	6
- actuarial loss	48	47	48
Other	0	0	0
Net settlement loss(a)	45 [1]	30 [1]	56 [1]
Net periodic benefit cost(b)	130 [2]	112 [2]	143 [2]
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):			
Actuarial loss (gain)	172	97	211
Amortization of actuarial (loss) gain	(93)	(77)	(167)
Prior service cost	0	0	0
Amortization of prior service credit (cost)	(7)	(6)	(13)
Spin-off downstream business (c)	0 [3]	(24) [3]	0 [3]
Total recognized in other comprehensive (income) loss	72	(10)	31
Total recognized in net periodic benefit cost and other comprehensive (income) loss	202	102	174
Foreign Pension Plans, Defined Benefit [Member]			
Components of net periodic benefit cost:			
Service cost	19	19	19
Interest cost	22	22	22
Expected return on plan assets	(22)	(23)	(22)
Depreciation, Depletion and Amortization [Abstract]			
- prior service cost (credit)	1	0	0
- actuarial loss	4	2	5
Other	0	0	2
Net settlement loss(a)	0 [1]	0 [1]	0 [1]
Net periodic benefit cost(b)	24 [2]	20 [2]	26 [2]
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):			
Actuarial loss (gain)	15	24	(25)
Amortization of actuarial (loss) gain	(4)	(2)	(5)
Prior service cost	1	(11)	0

Amortization of prior service credit (cost)	(1)	0	0
Spin-off downstream business (c)	0 [3]	0 [3]	0 [3]
Total recognized in other comprehensive (income) loss	11	11	(30)
Total recognized in net periodic benefit cost and other comprehensive (income) loss	35	31	(4)
Other Postretirement Benefit Plans, Defined Benefit [Member]			
Components of net periodic benefit cost:			
Service cost	4	4	3
Interest cost	14	16	16
Expected return on plan assets	0	0	0
Depreciation, Depletion and Amortization [Abstract]			
- prior service cost (credit)	(7)	(7)	(7)
- actuarial loss	0	0	0
Other	0	0	0
Net settlement loss(a)	0 [1]	0 [1]	0 [1]
Net periodic benefit cost(b)	11 [2]	13 [2]	12 [2]
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):			
Actuarial loss (gain)	7	1	69
Amortization of actuarial (loss) gain	0	0	2
Prior service cost	0	0	0
Amortization of prior service credit (cost)	7	7	6
Spin-off downstream business (c)	0 [3]	0 [3]	0 [3]
Total recognized in other comprehensive (income) loss	14	8	77
Total recognized in net periodic benefit cost and other comprehensive (income) loss	25	21	89
Subsequent Event [Member] | Other Postretirement Benefit Plans, Defined Benefit [Member]			
Pension and Other Postretirement Benefit Plans, Amounts that Will be Amortized from Accumulated Other Comprehensive Income (Loss) in Next Fiscal Year [Abstract]			
Defined Benefit Plan, Amortization of Net Gains (Losses)	1		
Defined Benefit Plan, Amortization of Net Prior Service Cost (Credit)	7		
Subsequent Event [Member] | United States and Foreign Pension Plans Defined Benefit [Member]			
Pension and Other Postretirement Benefit Plans, Amounts that Will be Amortized from Accumulated Other Comprehensive Income (Loss) in Next Fiscal Year [Abstract]			
Defined Benefit Plan, Amortization of Net Gains (Losses)	52		
Defined Benefit Plan, Amortization of Net Prior Service Cost (Credit)	$ 7		

[1] Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2012, 2011 and 2010.

[2] Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

[3] Includes net inter-company transfers of (gains)/losses due to the spin-off of the downstream business.

Fair Value Measurements (Details 3-Reported) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012		Dec. 31, 2011	
Fair Value [Member]				
Financial assets				
Other current assets	$ 2		$ 146	
Other noncurrent assets	189		68	
Total financial assets	191		214	
Financial liabilities				
Other current liabilities	13		0	
Long-term debt, including current portion(a)	7,610	[1]	5,479	[1]
Deferred credits and other liabilities	94		36	
Total financial liabilities	7,717		5,515	
Carrying Amount [Member]				
Financial assets				
Other current assets	2		148	
Other noncurrent assets	186		68	
Total financial assets	188		216	
Financial liabilities				
Other current liabilities	13		0	
Long-term debt, including current portion(a)	6,642	[1]	4,753	[1]
Deferred credits and other liabilities	94		38	
Total financial liabilities	$ 6,749		$ 4,791	

[1] Excludes capital leases

Property, Plant and Equipment (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012	Dec. 31, 2011
Segment Reporting Information [Line Items]		
Less accumulated depreciation, depletion and amortization	$ (19,266)	$ (17,248)
Property, plant and equipment, net	28,272	25,324
United States Exploration and Production [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, gross	23,400	19,679
International Exploration and Production [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, gross	13,523	12,579
Exploration and Production Segment [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, gross	36,923	32,258
Oil Sands Mining Segment [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, gross	10,128	9,936
Integrated Gas Segment [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, gross	38	37
Corporate [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, gross	449	341
Total All Segments [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, gross	47,538	42,572
Libya [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, net	$ 745	
Proved Developed and Undeveloped Reserves, Net (BOE)	244,000,000	

Asset Retirement Obligations (Notes)	12 Months Ended Dec. 31, 2012
Asset Retirement Obligation Disclosure [Abstract]	
Asset Retirement Obligations	**Asset Retirement Obligations** The following summarizes the changes in asset retirement obligations: (see table below)

Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2012	2011
Beginning balance	$ 1,510	$ 1,355
Incurred, including acquisitions	150	37
Settled, including dispositions	(35)	(39)
Accretion expense (included in depreciation, depletion and amortization)	91	81
Revisions to previous estimates	150	126
Held for sale	(83)	—
Spin-off downstream business	—	(50)
Ending balance[a]	$ 1,783	$ 1,510

[a] Includes asset retirement obligations of $34 million classified as a short-term at December 31, 2012.

Incentive Based Compensation Plans (Tables)	12 Months Ended Dec. 31, 2012
Incentive Based Compensation Plans [Abstract]	

Share-based Compensation Arrangement by Share-based Payment Award, Options, Grants in Period, Weighted Average Grant Date Fair Value

During 2012, 2011 and 2010, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following Black-Scholes assumptions:

	2012	2011	2010
Weighted average exercise price per share	$33.52	$32.30	$30.00
Expected annual dividend yield	2.2%	2.1%	3.2%
Expected life in years	5.6	5.3	5.1
Expected volatility	41%	40%	43%
Risk-free interest rate	1.2%	1.7%	2.2%
Weighted average grant date fair value of stock option awards granted	$10.86	$10.44	$8.70

Schedule of Share-based Compensation, Stock Options, Activity

The following is a summary of stock option award activity in 2012.

	Number of Shares	Weighted Average Exercise price
Outstanding at beginning of year	21,370,715	$24.41
Granted	1,858,872	$33.52
Exercised	(2,795,612)	$16.46
Cancelled	(897,010)	$29.29
Outstanding at end of year	19,536,965	$26.19

Schedule of Share-based Compensation, Shares Authorized under Stock Option Plans, by Exercise Price Range

The following table presents information related to stock option awards at December 31, 2012.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Option	Weighted Average Exercise Price
$ 7.99-12.75	429,685	1	$10.06	429,685	$10.06
12.76-16.81	2,307,526	4	$15.18	2,307,526	$15.18
16.82-23.20	5,409,048	7	$18.60	4,105,057	$18.55
23.21-29.24	2,031,690	5	$24.63	1,599,222	$23.79
29.25-36.03	6,809,564	6	$32.93	3,272,482	$32.50
36.04-46.41	2,549,452	6	$38.25	2,549,452	$38.25
Total	19,536,965	6	$26.19	14,263,424	$25.41

Schedule of Nonvested Restricted Stock Units Activity

The following is a summary of restricted stock award activity in 2012.

	Awards	Weighted Average Grant Date Fair Value

Unvested at beginning of year	3,703,978	$25.88
Granted	2,202,774	$31.59
Vested	(1,254,320)	$24.90
Forfeited	(474,548)	$27.26
Unvested at end of year	4,177,884	$29.02

Property, Plant and Equipment (Tables)

12 Months Ended Dec. 31, 2012

Property Plant And Equipment Disclosure [Abstract]

Schedule Of Property Plant And Equipment

Property, Plant and Equipment

(In millions)	December 31, 2012	2011
E&P		
United States	$ 23,400	$ 19,679
International	13,523	12,579
Total E&P	36,923	32,258
OSM	10,128	9,936
IG	38	37
Corporate	449	341
Total property, plant and equipment	$ 47,538	$ 42,572
Less accumulated depreciation, depletion and amortization	(19,266)	(17,248)
Net property, plant and equipment	$ 28,272	$ 25,324

Schedule of Aging of Capitalized Exploratory Well Costs

Deferred exploratory well costs were as follows:

(In millions)	December 31, 2012	2011	2010
Amounts capitalized less than one year after completion of drilling	$ 388	$ 482	$ 334
Amounts capitalized greater than one year after completion of drilling	229	222	323
Total deferred exploratory well costs	$ 617	$ 704	$ 657
Number of projects with costs capitalized greater than one year after completion of drilling	6	5	7

(In millions)	2012	2011	2010
Beginning balance	$ 704	$ 657	$ 829
Additions	731	670	329
Dry well expense	(143)	(268)	(83)
Transfers to development	(629)	(279)	(54)
Dispositions	(46)	(76)	(364)
Ending balance	$ 617	$ 704	$ 657

Schedule of Projects with Exploratory Well Costs Capitalized for More than One Year

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2012 are summarized by geographical area below:

(In millions)	
Angola	$ 128
Norway	70

E.G.	22
U.S.	9
Total	$ 229

Fair Value Measurements (Details-Recurring) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012	Dec. 31, 2011
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	$ 92	
Commodity [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	53	
Interest rate [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	21	
Foreign Exchange Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	18	
Fair Value, Inputs, Level 1 [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value, Inputs, Level 1 [Member] | Commodity [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value, Inputs, Level 1 [Member] | Interest rate [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value, Inputs, Level 1 [Member] | Foreign Exchange Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value, Inputs, Level 2 [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	91	
Fair Value, Inputs, Level 2 [Member] | Commodity [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	52	
Fair Value, Inputs, Level 2 [Member] | Interest rate [Member]		

Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	21	5
Fair Value, Inputs, Level 2 [Member] | Foreign Exchange Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	18	
Fair Value, Inputs, Level 3 [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value, Inputs, Level 3 [Member] | Commodity [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value, Inputs, Level 3 [Member] | Interest rate [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value, Inputs, Level 3 [Member] | Foreign Exchange Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value (no inputs) Collateral [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	1	
Fair Value (no inputs) Collateral [Member] | Commodity [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	1	
Fair Value (no inputs) Collateral [Member] | Interest rate [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	0	
Fair Value (no inputs) Collateral [Member] | Foreign Exchange Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring Basis, Financial Statement [Line Items]		
Derivative Assets	$ 0	

Stockholders Equity (Details) (USD $) Share data in Millions, unless otherwise specified	12 Months Ended	
	Dec. 31, 2012	Dec. 31, 2011
Stockholders' Equity Attributable to Parent [Abstract]		
Treasury Stock Amount Of Repurchase Authorization	$ 5,000,000,000	
Authorized Stock Repurchase Program Repurchased Number Of Shares	78	
Authorized Stock Repurchase Program Repurchase Amount	3,222,000,000	
Shares repurchased		12
Treasury stock value acquired under repurchase program cost method		$ 300,000,000

Segment Information (Tables)

12 Months Ended
Dec. 31, 2012

Segment Information Disclosure [Abstract]

Schedule of Segment Reporting Information, by Segment

(In millions)	E&P	OSM	IG	Total
2012				
Revenues:				
Customer	$ 14,026	$ 1,552	$ —	$ 15,578
Related parties	58	—	—	58
Segment revenues	$ 14,084	$ 1,552	$ —	15,636
Unrealized gain on crude oil derivative instruments				52
Total revenues				$ 15,688
Segment income	$ 1,881	$ 176	$ 91	$ 2,148
Income from equity method investments	238	—	132	370
Depreciation, depletion and amortization	2,226	217	—	2,443
Income tax provision	4,741	59	27	4,827
Capital expenditures	4,835	188	2	5,025

(In millions)	E&P	OSM	IG	Total
2011				
Revenues:				
Customer	$ 12,922	$ 1,588	$ 93	$ 14,603
Intersegment	47	—	—	47
Related parties	60	—	—	60
Segment revenues	$ 13,029	$ 1,588	$ 93	14,710
Elimination of intersegment revenues				(47)
Total revenues				$ 14,663
Segment income	$ 2,157	$ 256	$ 178	$ 2,591
Income from equity method investments	249	—	213	462
Depreciation, depletion and amortization	2,028	196	3	2,227
Income tax provision	2,808	82	74	2,964
Capital expenditures	3,038	308	2	3,348

(In millions)	E&P	OSM	IG	Total
2010				
Revenues:				
Customer	$ 10,651	$ 833	$ 150	$ 11,634
Intersegment	75	—	—	75
Related parties	56	—	—	56
Segment revenues	$ 10,782	$ 833	$ 150	11,765
Elimination of intersegment revenues				(75)
Total revenues				$ 11,690
Segment income (loss)	$ 1,941	$ (50)	$ 142	$ 2,033
Income from equity method investments	188	—	181	369
Depreciation, depletion and amortization	1,911	105	2	2,018
Income tax provision (benefit)	2,266	(12)	73	2,327
Capital expenditures	2,474	874	2	3,350

Reconciliation of Revenue from Segments to Consolidated

The following reconciles total revenues to sales and other operating revenues in the consolidated statements of income.

(In millions)	2012	2011	2010
Total revenues	$ 15,688	$ 14,663	$ 11,690
Less: Sales to related parties	58	60	56
Sales and other operating revenues	$ 15,630	$ 14,603	$ 11,634

Reconciliation Of Segment Income To Net Income

The following reconciles segment income to net income as reported in the consolidated statements of income.

(In millions)	2012	2011	2010
Segment income	$ 2,148	$ 2,591	$ 2,033
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(441)	(317)	(170)
Impairments	(231)	(195)	(286)
Gain on dispositions	72	45	407
Unrealized gain on crude oil derivative instruments	34	—	—
Loss on early extinguishment of debt	—	(176)	(57)
Tax effect of subsidiary restructuring	—	(122)	—
Deferred income tax items	—	(61)	(45)
Water abatement - Oil Sands	—	(48)	—
Eagle Ford transaction costs	—	(10)	—
Income from continuing operations	1,582	1,707	1,882
Discontinued operations	—	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568

Schedule of Revenue from External Customers Attributed to Foreign Countries by Geographic Area

The following summarizes revenues from external customers by geographic area.

(In millions)	2012	2011	2010
United States	$ 6,442	$ 6,971	$ 5,363
United Kingdom	1,245	1,546	1,063
Libya[a]	1,989	216	1,473
Norway	3,582	3,386	2,243
Canada	1,552	1,588	833
Other international	878	956	715
Total revenues	$ 15,688	$ 14,663	$ 11,690

[a] See Note 13 for discussion of Libya operations.

Revenue from External Customers by Products and Services

Revenues by product line were:

(In millions)	2012	2011	2010
Liquid hydrocarbons	$ 12,945	$ 11,717	$ 9,480
Natural gas	1,103	1,291	1,295
Synthetic crude oil	1,545	1,581	832
Transportation & other	95	74	83
Total revenues	$ 15,688	$ 14,663	$ 11,690

Schedule of Disclosure on Geographic Areas, Long-Lived Assets in Individual Foreign Countries by Country

The following summarizes certain long-lived assets by geographic area, including property, plant and equipment and equity investments.

(In millions)	2012	2011
United States	$ 13,677	$ 10,928
Canada	9,693	9,711
Equatorial Guinea	2,081	2,214
Norway	987	1,133
Other international	3,113	2,721
Total long-lived assets	$ 29,551	$ 26,707

Summary of Principal Accounting Policies Revision (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Other Comprehensive Income (Loss), Pension and Other Postretirement Benefit Plans, Adjustment, Net of Tax	$ 62	$ (36) [1]	$ 69
Other Comprehensive Income (Loss), Derivatives Qualifying as Hedges, Net of Tax	(1)	(5) [1]	(6)
Revision [Member]			
Change In Accumulated Other Comprehensive Income Loss Net of Tax		587	
Other Comprehensive Income (Loss), Pension and Other Postretirement Benefit Plans, Adjustment, Net of Tax		(591)	
Other Comprehensive Income (Loss), Derivatives Qualifying as Hedges, Net of Tax		$ 4	

[1] See Note 1 – Summary of Principal Accounting Policies – Revision for additional information.

Income Taxes (Details 2) (USD $) In Millions, unless otherwise specified	3 Months Ended	12 Months Ended		
	Jun. 30, 2011	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Valuation Allowance [Abstract]				
Valuation Allowance Deferred Tax Asset Change In Amount Federal		$ 1,277	$ 585	$ (74)
Valuation Allowance Deferred Tax Asset Change In Amount Foreign	(228)	16	52	40
Assets				
Other current assets		57	99	
Other noncurrent assets		849	674	
Liabilities				
Other current liabilities		4	5	
Noncurrent deferred tax liabilities		2,432	2,544	
Net deferred tax liabilities		1,530	1,776	
Foreign Country Canada [Member]				
Operating Loss Carryforwards [Line Items]				
Deferred Tax Assets, Operating Loss Carryforwards		811		
Foreign Country Indonesia [Member]				
Operating Loss Carryforwards [Line Items]				
Deferred Tax Assets, Operating Loss Carryforwards		216		
State and Local Jurisdiction [Member]				
Operating Loss Carryforwards [Line Items]				
Deferred Tax Assets, Operating Loss Carryforwards		$ 1,363		

Segment Information (Details 2) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Reconciliation of total revenues to sales and other operating revenues (including consumer excise taxes) as reported in the consolidated statements of income:			
Total revenues	$ 15,688	$ 14,663	$ 11,690
Sales to related parties	58	60	56
Sales and other operating revenues	15,630	14,603	11,634
Segment income	2,148	2,591	2,033
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(441)	(317)	(170)
Impairments	(231)	(195)	(286)
Gain on dispositions	72	45	407
Unrealized gain on crude oil derivative instruments	34	0	0
Loss on early extinguishment of debt	0	(176)	(57)
Tax effect of subsidiary restructuring	0	(122)	0
Deferred income tax items	0	(61)	(45)
Water abatement - Oil Sands	0	(48)	0
Eagle Ford transaction costs	0	(10)	0
Income from continuing operations	1,582	1,707	1,882
Discontinued operations	0	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568

Asset Retirement Obligations (Tables)	12 Months Ended Dec. 31, 2012
Asset Retirement Obligation Disclosure [Abstract]	
Schedule of Change in Asset Retirement Obligation	The following summarizes the changes in asset retirement obligations:

(In millions)	2012	2011
Beginning balance	$ 1,510	$ 1,355
Incurred, including acquisitions	150	37
Settled, including dispositions	(35)	(39)
Accretion expense (included in depreciation, depletion and amortization)	91	81
Revisions to previous estimates	150	126
Held for sale	(83)	—
Spin-off downstream business	—	(50)
Ending balance[(a)]	$ 1,783	$ 1,510

(a) Includes asset retirement obligations of $34 million classified as a short-term at December 31, 2012.

Accounting Standards	12 Months Ended Dec. 31, 2012
Accounting Standards Disclosure [Abstract]	
Accounting Standards	

Accounting Standards

Not Yet Adopted

In February 2013, an accounting standards update was issued to improve the reporting of reclassifications out of accumulated other comprehensive income. This standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. These disclosures are effective for us beginning the first quarter of 2013. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In December 2011 an accounting standards update designed to enhance disclosures about offsetting assets and liabilities was issued. Further clarification limiting the scope of these disclosures to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions was issued in January 2013. The disclosures are intended to enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity’s financial position. Entities are required to disclose both gross information and net information about in-scope financial instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. These disclosures are effective for us beginning the first quarter of 2013 and must be made retrospectively for comparable periods. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In September 2011, the FASB amended accounting standards to simplify how entities test goodwill for impairment. The amendment reduces complexity by allowing an entity the option to make a qualitative evaluation of whether it is necessary to perform the two-step goodwill impairment test. The amendment was effective for our interim and annual periods beginning with the first quarter of 2012. Adoption of this amendment did not have a significant impact on our consolidated results of operations, financial position or cash flows.

The FASB amended the reporting standards for comprehensive income in June 2011 to eliminate the option to present the components of OCI as part of the statement of changes in stockholders' equity. All non-owner changes in stockholders’ equity are required to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of OCI, and total comprehensive income. The presentation of items that are reclassified from OCI to net income on the income statement is also required. The amendments did not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The amendments were effective for us beginning with the first quarter of 2012, except for the presentation of reclassifications, which was deferred and addressed in the February 2013 accounting standards update discussed above. Adoption of these amendments did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2011, the FASB issued an update amending the accounting standards for fair value measurement and disclosure, resulting in common principles and requirements under U.S. GAAP and IFRS. The amendments change the wording used to describe certain of the U.S. GAAP requirements either to clarify the intent of existing requirements, to change measurement or expand disclosure principles or to conform to the wording used in IFRS. The amendments were to be applied prospectively for our interim and annual periods beginning with the first quarter of 2012. The adoption of the amendments did not have a significant impact on our consolidated results of operations, financial position or cash flows. To the extent they were necessary, we made the expanded disclosures in Notes 15 and 20.

Segment Information (Details 3) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Revenues from External Customers and Long-Lived Assets [Line Items]			
Revenue, Net	$ 15,688	$ 14,663	$ 11,690
Long-Lived Assets	29,551	26,707	
United States [Member]			
Revenues from External Customers and Long-Lived Assets [Line Items]			
Revenue, Net	6,442	6,971	5,363
Long-Lived Assets	13,677	10,928	
UK [Member]			
Revenues from External Customers and Long-Lived Assets [Line Items]			
Revenue, Net	1,245	1,546	1,063
Libya [Member]			
Revenues from External Customers and Long-Lived Assets [Line Items]			
Revenue, Net	1,989 [1]	216 [1]	1,473 [1]
Norway [Member]			
Revenues from External Customers and Long-Lived Assets [Line Items]			
Revenue, Net	3,582	3,386	2,243
Long-Lived Assets	987	1,133	
Canada [Member]			
Revenues from External Customers and Long-Lived Assets [Line Items]			
Revenue, Net	1,552	1,588	833
Long-Lived Assets	9,693	9,711	
Other International [Member]			
Revenues from External Customers and Long-Lived Assets [Line Items]			
Revenue, Net	878	956	715
Long-Lived Assets	3,113	2,721	
Equatorial Guinea [Member]			
Revenues from External Customers and Long-Lived Assets [Line Items]			
Long-Lived Assets	$ 2,081	$ 2,214	

[1] See Note 13 for discussion of Libya operations.

Goodwill (Tables)	12 Months Ended Dec. 31, 2012

Goodwill Disclosure [Abstract]

Schedule of Goodwill

The changes in the carrying amount of goodwill for the years ended December 31, 2012 and 2011 were as follows:

(In millions)	E&P	OSM	Downstream business	Total
2011				
Beginning balance, gross	$ 537	$ 1,412	$ 843	$ 2,792
Less: accumulated impairment	—	(1,412)	—	(1,412)
Beginning balance, net	537	—	843	1,380
Contingent consideration adjustment	—	—	(3)	(3)
Purchase price adjustment	—	—	9	9
Dispositions	(1)	—	(2)	(3)
Spin-off downstream business	—	—	(847)	(847)
Ending balance, net	536	—	—	536
2012				
Beginning balance, gross	536	1,412	—	1,948
Less: accumulated impairments	—	(1,412)	—	(1,412)
Beginning balance, net	536	—	—	536
Dispositions	(11)	—	—	(11)
Ending balance, net	$ 525	$ —	$ —	$ 525

Stockholders Equity (Notes)	12 Months Ended Dec. 31, 2012
Stockholders' Equity Attributable to Parent [Abstract]	
Stockholders’ Equity	**Stockholders’ Equity** ***Share repurchase plan*** – The Board of Directors has authorized the repurchase of up to $5 billion of our common stock. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables. As of December 31, 2012, we had acquired 78 million common shares at a cost of $3,222 million under this authorized share repurchase program, including 12 million common shares acquired in 2011 after the June 30, 2011 spin-off of our downstream business at a cost of $300 million.

Incentive Based Compensation Plans	12 Months Ended Dec. 31, 2012
Incentive Based Compensation Plans [Abstract]	
Incentive Based Compensation	**Incentive Based Compensation**

Description of stock based compensation plans

The Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan") was approved by our stockholders in April 2012 and authorizes the Compensation Committee of the Board of Directors to grant stock options, SARs, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2012 Plan also allows us to provide equity compensation to our non-employee directors. No more than 50 million shares of our common stock may be issued under the 2012 Plan. For stock options and SARs, the number of shares available for issuance under the 2012 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted. For awards other than stock options or SARs, the number of shares available for issuance under the 2012 Plan will be reduced by 2.41 shares for each share of our common stock in respect of which the award is granted.

Shares subject to awards under the 2012 Plan that are forfeited, are terminated or expire unexercised become available for future grants. If a SAR is settled upon exercise by delivery of shares of common stock, the full number of shares with respect to which the SAR was exercised will count against the number of shares of our common stock reserved for issuance under the 2012 Plan and will not again become available under the 2012 Plan. In addition, the number of shares of our common stock reserved for issuance under the 2012 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2012 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2012 Plan, no new grants were or will be made from the 2007 Incentive Compensation Plan (the "2007 Plan"), the 2003 Incentive Compensation Plan (the "2003 Plan"), the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (the "Prior Plans"). Any awards previously granted under the 2007 Plan, the 2003 Plan or the Prior Plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock based awards under the plans

Stock options – We grant stock options under the 2012 Plan and previously granted stock options under the 2007 Plan and the 2003 Plan. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. Through 2004, certain stock options were granted under the 2003 Plan with a tandem SAR, which allows the recipient to instead elect to receive cash or our common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the 2003 Plan, over the option price of the shares. In general, stock options granted under the 2012 Plan, the 2007 Plan and the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights – Prior to 2005, we granted SARs under the 2003 Plan. No SARs have been granted under the 2012 Plan or the 2007 Plan. Similar to stock options, SARs represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Under the 2003 Plan, certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs granted under the 2003 Plan vested ratably over a three-year period and have a maximum term of ten years from the date they were granted.

Restricted stock – We grant restricted stock and restricted stock units ("restricted stock awards") under the 2012 Plan and previously granted such awards under the 2007 Plan and the 2003 Plan. The restricted stock awards granted officers vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees, based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Common stock units – We maintain an equity compensation program for our non-employee directors under the 2012 Plan and previously maintained such a program under the 2007 Plan and the 2003 Plan. All non-employee directors receive annual grants of common stock units. Those units granted prior to 2012 must be held until completion of board service, at which time the non-employee director will receive common shares. Common shares will be issued for units granted on or after January 1, 2012 upon completion of board service or three years from the date of grant, whichever is earlier. When dividends are paid on our common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock based compensation expense

Total employee stock based compensation expense was $70 million, $65 million and $51 million in 2012, 2011 and 2010, while the total related income tax benefits were $25 million, $23 million and $19 million in the same years. In 2012, 2011 and 2010, cash received upon exercise of stock option awards was $41 million, $77 million and $12 million. Tax benefits realized for deductions for stock awards exercised during 2012, 2011 and 2010 totaled $24 million, $32 million and $11 million.

Stock option awards

During 2012, 2011 and 2010, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following Black-Scholes assumptions:

	2012	2011	2010
Weighted average exercise price per share	$33.52	$32.30	$30.00
Expected annual dividend yield	2.2%	2.1%	3.2%
Expected life in years	5.6	5.3	5.1
Expected volatility	41%	40%	43%
Risk-free interest rate	1.2%	1.7%	2.2%
Weighted average grant date fair value of stock option awards granted	$10.86	$10.44	$8.70

The following is a summary of stock option award activity in 2012.

	Number of Shares	Weighted Average Exercise price
Outstanding at beginning of year	21,370,715	$24.41

Granted	1,858,872	$33.52
Exercised	(2,795,612)	$16.46
Cancelled	(897,010)	$29.29
Outstanding at end of year	19,536,965	$26.19

The intrinsic value of stock option awards exercised during 2012, 2011 and 2010 was $40 million, $59 million and $8 million.

The following table presents information related to stock option awards at December 31, 2012.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Option	Weighted Average Exercise Price
$ 7.99-12.75	429,685	1	$10.06	429,685	$10.06
12.76-16.81	2,307,526	4	$15.18	2,307,526	$15.18
16.82-23.20	5,409,048	7	$18.60	4,105,057	$18.55
23.21-29.24	2,031,690	5	$24.63	1,599,222	$23.79
29.25-36.03	6,809,564	6	$32.93	3,272,482	$32.50
36.04-46.41	2,549,452	6	$38.25	2,549,452	$38.25
Total	19,536,965	6	$26.19	14,263,424	$25.41

As of December 31, 2012, the aggregate intrinsic value of stock option awards outstanding was $122 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $105 million and 5 years.

As of December 31, 2012, the number of fully-vested stock option awards and stock option awards expected to vest was 19,466,855. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $26.18 and 6 years and the aggregate intrinsic value was $122 million. As of December 31, 2012, unrecognized compensation cost related to stock option awards was $22 million, which is expected to be recognized over a weighted average period of 1 year.

Restricted stock awards

The following is a summary of restricted stock award activity in 2012.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	3,703,978	$25.88
Granted	2,202,774	$31.59
Vested	(1,254,320)	$24.90
Forfeited	(474,548)	$27.26
Unvested at end of year	4,177,884	$29.02

The vesting date fair value of restricted stock awards which vested during 2012, 2011 and 2010 was $36 million, $30 million and $21 million. The weighted average grant date fair value of restricted stock awards was $29.02, $25.88, and $23.03 for awards unvested at December 31, 2012, 2011 and 2010.

As of December 31, 2012, there was $94 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 1.2 years.

Performance unit awards

Performance units provide for executive officers to receive a cash payment upon the achievement of certain performance goals at the end of a defined measurement period. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. The target value of each performance unit is $1, with a maximum payout of $2 per unit, but the actual payout could be anywhere between zero and the maximum. Because performance units are to be settled in cash at the end of the performance period, they are accounted for as liability awards. Compensation expense associated with performance units was $12 million and $32 million in 2012 and 2011, but was not significant in 2010. Expense for 2011 included $14 million paid on three groups of performance unit grants outstanding June 30, 2011, that were accelerated with the total payout determined based on performance through the effective date of the spin-off of our downstream business.

During 2012, we granted 12.7 million performance units. These units have a 36-month performance period. During the third quarter of 2011, we granted 15 million performance units. A portion of the units granted in 2011 had an 18-month performance period and a portion had a 30-month performance period to reflect the remaining periods of the original 2011 and 2010 performance unit grants outstanding prior to the spin-off. The performance period for the units with an 18-month performance period ended December 31, 2012.

Acquisitions (Details) (Eagle Ford [Member], USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011 acre
Eagle Ford [Member]	
Business Acquisition [Line Items]	
Eagle Ford Hilcorp Acerage	108,000
Business Acquisition, Cost of Acquired Entity, Cash Paid	$ 265

Fair Value Measurements Fair Value Measurements (Tables)	12 Months Ended Dec. 31, 2012

Fair Value Disclosures [Abstract]

Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis

The following table presents assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2012 by fair value hierarchy level.

	December 31, 2012				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ —	$ 52	$ —	$ 1	$ 53
Interest rate	—	21	—	—	21
Foreign currency	—	18	—	—	18
Derivative instruments, assets	$ —	$ 91	$ —	$ 1	$ 92

Fair Value, Assets and Liabilities Measured on Nonrecurring Basis

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	2012		2011		2010	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 16	$ 371	$ 226	$ 285	$ 147	$ 447
Long-lived assets held for sale	—	—	—	—	85	64
Intangible assets	—	—	—	25	—	—
Equity method investments	—	—	—	—	—	25

Fair Value, by Balance Sheet Grouping

The following table summarizes financial instruments, excluding trade accounts receivable, commercial paper, payables and derivative financial instruments and their reported fair value, by individual balance sheet line item at December 31, 2012 and 2011.

	December 31,			
	2012		2011	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 2	$ 2	$ 146	$ 148
Other noncurrent assets	189	186	68	68
Total financial assets	191	188	214	216
Financial liabilities				
Other current liabilities	13	13	—	—
Long-term debt, including current portion[(a)]	7,610	6,642	5,479	4,753

Deferred credits and other liabilities	94	94	36	38
Total financial liabilities	$ 7,717	$ 6,749	$ 5,515	$ 4,791

[a] Excludes capital leases.

Leases (Notes)

12 Months Ended Dec. 31, 2012

Leases [Abstract]

Leases

Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations and for operating lease obligations having initial or remaining noncancellable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2013	$ 1	$ 42
2014	1	36
2015	1	33
2016	1	29
2017	1	21
Later years	24	49
Sublease rentals	—	(2)
Total minimum lease payments	$ 29	$ 208
Less imputed interest costs	(18)	
Present value of net minimum lease payments	$ 11	

Operating lease rental expense was $74 million, $74 million and $77 million in 2012, 2011 and 2010, which excludes $16 million paid by United States Steel on assumed leases in 2010.

Commitments and Contingencies	12 Months Ended Dec. 31, 2012
Commitments and Contingencies Disclosure [Abstract]	
Commitments and Contingencies	

Commitments and Contingencies

We are a defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Litigation – In March 2011, Noble Drilling (U.S.) LLC ("Noble") filed a lawsuit against us in the District Court of Harris County, Texas alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. Noble is seeking an unspecified amount of damages. We are vigorously defending this litigation. The ultimate outcome of this lawsuit, including any financial effect on us, remains uncertain. We do not believe an estimate of a reasonably probable loss (or range of loss) can be made for this lawsuit at this time.

Environmental matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2012 and 2011, accrued liabilities for remediation were not significant. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees **–** We have various performance guarantees related to specific agreements as discussed below. Under the terms of most of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain facilities formerly owned by United States Steel. We have agreed, under certain circumstances, to indemnify the limited partners if the partnership's product sales fail to qualify for the credit under Section 29 of the Internal Revenue Code. The Clairton 1314B Partnership was terminated on October 31, 2008, but we were not released from our obligations. United States Steel has estimated the maximum potential amount of this indemnity obligation, including interest and tax gross-up, was approximately $110 million as of December 31, 2012.

After our 2009 sale of the subsidiary holding our interest in the Corrib natural gas development offshore Ireland, one guarantee of that entity's performance related to asset retirement obligations remains issued to certain Irish government entities until the Irish government and the current Corrib partners agree to release our guarantee and accept the purchaser's guarantee to replace it. We have been indemnified by the purchaser of the subsidiary and have the benefit of a letter of credit. The maximum potential undiscounted payments related to asset retirement obligations under this guarantee as of December 31, 2012 are $40 million.

We have entered into other guarantees with maximum potential undiscounted payments totaling $94 million as of December 31, 2012, which consist primarily of a performance guarantee and a long-term transportation services agreement.

In October 2010, upon acquiring a position in four exploration blocks in the Kurdistan Region of Iraq, we indemnified the KRG against any negative tax effects related to certain payments we are obligated to make to the KRG. As of December 31, 2012, some of those payments had been made, no related taxes have been assessed, and neither is there any history of such payments being taxed. Given the lack of history of tax assessment against such payments, and because certain of our future payments to the KRG are not quantifiable, a maximum potential undiscounted payments cannot be calculated.

Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Contract commitments – At December 31, 2012 and 2011, contractual commitments to acquire property, plant and equipment totaled $949 million and $615 million.

Other contingencies – During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. Our share of the estimated costs in the amount of $64 million was recorded to cost of revenues in 2011. At December 31, 2012, the remaining liability is $39 million.

Summary of Principal Accounting Policies	**12 Months Ended Dec. 31, 2012**
Accounting Policies [Abstract]	
Summary of Principal Accounting Policies	

Summary of Principal Accounting Policies

We are engaged in worldwide exploration, production and marketing of liquid hydrocarbons and natural gas; oil sands mining, bitumen transportation and upgrading, marketing of synthetic crude oil and vacuum gas oil in Canada; and production and marketing of products manufactured from natural gas, such as LNG and methanol in E.G.

Principles applied in consolidation – These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries and variable interest entities for which we are the primary beneficiary.

Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority stockholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees.

Equity method investments are carried at our share of net assets plus loans and advances. Such investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in net income. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

As a result of the spin-off of our downstream business (see Note 3), the results of operations and cash flows for the downstream business have been classified as discontinued operations for 2011 and 2010. The disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated.

Use of estimates – The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Revision – We have revised our 2011 consolidated statement of comprehensive income to exclude the effects of the spin-off of our former downstream business. Changes in accumulated other comprehensive loss of $587 million, net of tax, associated with postretirement and postemployment plans ($591 million, net of tax) and unrecognized derivative hedging losses ($4 million, net of tax) related to the downstream business were removed from this statement. The revision had no impact on our consolidated balance sheets or consolidated statements of income, cash flows or stockholders' equity for any periods presented.

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. Costs associated with revenues are recorded in cost of revenues.

In the lower 48 states of the U.S., production volumes of liquid hydrocarbons and natural gas are sold immediately and transported to market. In Alaska and international locations, liquid hydrocarbon and natural gas production volumes may be stored as inventory and sold at a later time. In Canada, mined bitumen is first processed through an upgrader and then sold as synthetic crude oil. Both bitumen and synthetic crude oil may be stored as inventory.

We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

Cash and cash equivalents – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable – The majority of our receivables are from joint interest owners in properties we operate, or from purchasers of commodities, both of which are recorded at invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. Uncollectible accounts receivable are reserved against the allowance for uncollectible accounts when it is determined the receivable will not be collected and the amount of any reserve may be reasonably estimated.

Inventories – Inventories are carried at the lower of cost or market value. The majority of our inventories are recorded at average cost. The last-in, first-out ("LIFO") method is used for our U.S. crude oil and natural gas inventories.

We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

Derivative instruments – We may use derivatives to manage a portion of our exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk. All derivative instruments are recorded at fair value. Commodity derivatives are reflected on our consolidated balance sheet on a net basis by brokerage firm, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, interest rate risk and foreign currency exchange rate risk related to operating expenditures are classified in operating activities with the underlying transactions. Cash flows related to derivatives used to manage exchange rate risk related to capital expenditures denominated in foreign currencies are classified in investing activities with the underlying transactions. Our derivative instruments contain no significant contingent credit features.

Cash flow hedges – We may use foreign currency forwards and options to manage foreign currency risk associated with anticipated transactions, primarily expenditures for capital projects denominated in certain foreign currencies, and designate them as cash flow hedges. The effective portion of changes in fair value is recognized in other comprehensive income ("OCI") and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion is recognized in net interest and other as it occurs. For a discontinued cash flow hedge, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2012 and 2011.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio; commodity derivative instruments to manage the price risk on natural gas that we purchase to be marketed with our natural gas production; and foreign currency forwards to manage our exposure to changes in the value of foreign currency denominated tax liabilities. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Derivatives not designated as hedges – Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price risk on the forecasted sale of crude oil, natural gas and synthetic crude oil that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Concentrations of credit risk – All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

Property, plant and equipment – We use the successful efforts method of accounting for oil and gas producing activities, which include bitumen mining and upgrading.

Property acquisition costs – Costs to acquire mineral interests in traditional oil and natural gas properties or in oil sands mines, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and to construct or expand oil sands mines and upgrading facilities are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties, which include our bitumen mining and upgrading facilities, are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities are depreciated on a straight-line basis over their estimated useful lives which range from 3 to 43 years.

Property, plant and equipment unrelated to oil and gas producing activities is recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 40 years.

Impairments – We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells, development costs and our bitumen mining and upgrading facilities, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure. Impairment of proved properties is required when the carrying value exceeds the related undiscounted future net cash flows based on proved and probable reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors and may apply an undiscounted future net cash flow approach when appropriate. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage are also considered. When unproved property investments are deemed to be impaired the expense is reported in exploration expenses.

Dispositions – When property, plant and equipment depreciated on an individual basis are sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

Goodwill – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

Major maintenance activities – Costs for planned major maintenance are expensed in the period incurred. These types of costs include contractor repair services, materials and supplies, equipment rentals and our labor costs.

Environmental costs – Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed and determinable.

Asset retirement obligations – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities, which include our bitumen mining facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, mine assets, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals. Asset retirement obligations have not been recognized for certain of our international oil and gas producing facilities as we currently do not have a legal obligation associated with the retirement of those facilities. Asset retirement obligations have not been recognized for the removal of materials and equipment from or the closure of certain bitumen upgrading assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate.

Current inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and gas production facilities, which include our bitumen mining facilities, while accretion escalates over the lives of the assets.

Deferred income taxes – Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management’s intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

Stock based compensation arrangements – The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management’s best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of our stock price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards and common stock units is determined based on the market value of our common stock on the date of grant. Unearned stock-based compensation is charged to stockholders’ equity when restricted stock awards are granted.

Our stock-based compensation expense is recognized based on management’s best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods. Options with tandem SARs are classified as a liability and are remeasured at fair value each reporting period until settlement.

Fair value transfer – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. When significant transfers occur, they are disclosed in the appropriate footnote to the financial statements.

Summary of Principal Accounting Policies (Policies)

12 Months Ended Dec. 31, 2012

Accounting Policies [Abstract]

Principles applied in consolidation

Principles applied in consolidation – These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries and variable interest entities for which we are the primary beneficiary.

Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority stockholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees.

Equity method investments are carried at our share of net assets plus loans and advances. Such investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in net income. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

Use of estimates

Use of estimates – The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Revision

Revision – We have revised our 2011 consolidated statement of comprehensive income to exclude the effects of the spin-off of our former downstream business. Changes in accumulated other comprehensive loss of $587 million, net of tax, associated with postretirement and postemployment plans ($591 million, net of tax) and unrecognized derivative hedging losses ($4 million, net of tax) related to the downstream business were removed from this statement. The revision had no impact on our consolidated balance sheets or consolidated statements of income, cash flows or stockholders' equity for any periods presented.

Foreign currency transactions

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition

Revenue recognition – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. Costs associated with revenues are recorded in cost of revenues.

In the lower 48 states of the U.S., production volumes of liquid hydrocarbons and natural gas are sold immediately and transported to market. In Alaska and international locations, liquid hydrocarbon and natural gas production volumes may be stored as inventory and sold at a later time. In Canada, mined bitumen is first processed through an upgrader and then sold as synthetic crude oil. Both bitumen and synthetic crude oil may be stored as inventory.

Gas balancing

We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

Cash and cash equivalents

Cash and cash equivalents – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable

Accounts receivable – The majority of our receivables are from joint interest owners in properties we operate, or from purchasers of commodities, both of which are recorded at invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. Uncollectible accounts receivable are reserved against the allowance for uncollectible accounts when it is determined the receivable will not be collected and the amount of any reserve may be reasonably estimated.

Inventories

Inventories – Inventories are carried at the lower of cost or market value. The majority of our inventories are recorded at average cost. The last-in, first-out ("LIFO") method is used for our U.S. crude oil and natural gas inventories.

We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

Derivative instruments

Concentrations of credit risk – All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

Derivative instruments – We may use derivatives to manage a portion of our exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk. All derivative instruments are recorded at fair value. Commodity derivatives are reflected on our consolidated balance sheet on a net basis by brokerage firm, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, interest rate risk and foreign currency exchange rate risk related to operating expenditures are classified in operating activities with the underlying transactions. Cash flows related to derivatives used to manage exchange rate risk related to capital expenditures denominated in foreign currencies are classified in investing activities with the underlying transactions. Our derivative instruments contain no significant contingent credit features.

Cash flow and Fair value hedges

Cash flow hedges – We may use foreign currency forwards and options to manage foreign currency risk associated with anticipated transactions, primarily expenditures for capital projects denominated in certain foreign currencies, and designate them as cash flow hedges. The effective portion of changes in fair value is recognized in other comprehensive income ("OCI") and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion is recognized in net interest and other as it occurs. For a discontinued cash flow hedge, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2012 and 2011.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio; commodity derivative instruments to manage the price risk on natural gas that we purchase to be marketed with our natural gas production; and foreign currency forwards to manage our exposure to changes in the value of foreign currency denominated tax liabilities. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Derivatives not designated as hedges

Derivatives not designated as hedges – Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price risk on the forecasted sale of crude oil, natural gas and synthetic crude oil that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Property, plant and equipment

Property, plant and equipment – We use the successful efforts method of accounting for oil and gas producing activities, which include bitumen mining and upgrading.

Property acquisition costs

Property acquisition costs – Costs to acquire mineral interests in traditional oil and natural gas properties or in oil sands mines, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and to construct or expand oil sands mines and upgrading facilities are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties, which include our bitumen mining and upgrading facilities, are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities are depreciated on a straight-line basis over their estimated useful lives which range from 3 to 43 years.

Property, plant and equipment unrelated to oil and gas producing activities is recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 40 years.

Impairments

Impairments – We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells, development costs and our bitumen mining and upgrading facilities, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure. Impairment of proved properties is required when the carrying value exceeds the related undiscounted future net cash flows based on proved and probable reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors and may apply an undiscounted future net cash flow approach when appropriate. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage are also considered. When unproved property investments are deemed to be impaired the expense is reported in exploration expenses.

Dispositions

Dispositions – When property, plant and equipment depreciated on an individual basis are sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

Goodwill

Goodwill – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

Major maintenance activities

Major maintenance activities – Costs for planned major maintenance are expensed in the period incurred. These types of costs include contractor repair services, materials and supplies, equipment rentals and our labor costs.

Environmental costs

Environmental costs – Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed and determinable.

Asset retirement obligations

Asset retirement obligations – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities, which include our bitumen mining facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, mine assets, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals. Asset retirement obligations have not been recognized for certain of our international oil and gas producing facilities as we currently do not have a legal obligation associated with the retirement of those facilities. Asset retirement obligations have not been recognized for the removal of materials and equipment from or the closure of certain bitumen upgrading assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate.

Current inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and gas production facilities, which include our bitumen mining facilities, while accretion escalates over the lives of the assets.

Deferred income taxes

Deferred income taxes – Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management's intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

Stock based compensation arrangements

Stock based compensation arrangements – The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of our stock price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards and common stock units is determined based on the market value of our common stock on the date of grant. Unearned stock-based compensation is charged to stockholders' equity when restricted stock awards are granted.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods. Options with tandem SARs are classified as a liability and are remeasured at fair value each reporting period until settlement.

Fair Value Transfer, Policy [Policy Text Block]

Fair value transfer – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. When significant transfers occur, they are disclosed in the appropriate footnote to the financial statements.

Debt (Details 1) (USD $)	1 Months Ended	2 Months Ended	3 Months Ended	12 Months Ended				0 Months Ended		0 Months Ended								1 Months Ended				1 Months Ended		
	Apr. 30, 2012	Mar. 31, 2011	Mar. 31, 2011	Dec. 31, 2012 extension	Dec. 31, 2011	Dec. 31, 2010	Apr. 30, 2012 Secured Debt [Member] Revolving Credit Facility [Member] Federal Funds Rate [Member]	Oct. 29, 2012 Senior Unsecured Notes Due 2015 [Member]	Dec. 31, 2012 Senior Unsecured Notes Due 2015 [Member]	Oct. 29, 2012 Senior Unsecured Notes Due 2022 [A] [Member]	Dec. 31, 2012 Senior Unsecured Notes Due 2022 [A] [Member]	Dec. 31, 2012 Obligation Relating To Revenue Bonds Due 2013 [Member]	Jun. 30, 2012 Obligation Relating To Revenue Bonds Due 2013 [Member]	Apr. 30, 2012 Prior [Member]	Apr. 30, 2012 Current [Member]	Apr. 30, 2012 Bridge Loan [Member]	Apr. 30, 2012 Letter of Credit [Member]	Apr. 30, 2012 Minimum [Member] Current [Member]	Apr. 30, 2012 Minimum [Member] Libor [Member] Current [Member]	Apr. 30, 2012 Minimum [Member] Base Rate [Member] Current [Member]	Apr. 30, 2012 Minimum [Member] Base Rate [Member] One Month Libor Plus [Member] Current [Member]	Apr. 30, 2012 Maximum [Member] Current [Member]	Apr. 30, 2012 Maximum [Member] Libor [Member] Current [Member]	Apr. 30, 2012 Maximum [Member] Base Rate [Member] Current [Member]
Debt Instrument [Line Items]																								
Commercial paper				$ 200,000,000	$ 0																			
Line of Credit Facility, Maximum Borrowing Capacity														3,000,000,000	2,500,000,000	100,000,000	500,000,000							
Line of Credit Facility, Expiration Date	Apr. 30, 2017																							
Line Of Credit Extended Borrowing Capacity															1,000,000,000									
Debt Instrument, Basis Spread on Variable Rate							0.50%												0.875%	0.00%	1.00%		1.625%	0.625%
Ratio of Indebtedness to Net Capital															0.65									
Debt Instrument, Face Amount									1,000,000,000 [1]		1,000,000,000 [1]													
Debt Instrument, Interest Rate, Stated Percentage									0.90% [1]		2.80% [1]	5.375%	5.375%											
Debt Instrument, Maturity Date								Nov. 01, 2015		Nov. 01, 2022														
Line of Credit Facility, Unused Capacity, Commitment Fee Percentage																		0.10%				0.25%		
Extinguishment of Debt, Amount		2,498,000,000																						
Debt Extinguished Percent Of Face Value		112.00%																						
Loss on early extinguishment of debt			$ 279,000,000	$ 0	$ 279,000,000	$ 92,000,000																		
Line of Credit Facility, Number of One Year Extensions				2																				
Line of Credit Facility, Period of Operation	5 years																							

[1] These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

Inventories (Tables)	**12 Months Ended Dec. 31, 2012**
Inventory Disclosure [Abstract]	
Schedule of Inventory, Current	

	December 31,	
(In millions)	2012	2011
Liquid hydrocarbons, natural gas and bitumen	$ 73	$ 147
Supplies and sundry items	288	214
Inventories at cost	$ 361	$ 361

Depreciation, depletion and amortization (Details)	12 Months Ended Dec. 31, 2012
Wells and Related Equipment and Facilities [Member] | Minimum [Member]	
Property, Plant and Equipment [Line Items]	
Property, Plant and Equipment, Useful Life	3 years
Wells and Related Equipment and Facilities [Member] | Maximum [Member]	
Property, Plant and Equipment [Line Items]	
Property, Plant and Equipment, Useful Life	43 years
Property, Plant and Equipment, Other Types [Member] | Minimum [Member]	
Property, Plant and Equipment [Line Items]	
Property, Plant and Equipment, Useful Life	3 years
Property, Plant and Equipment, Other Types [Member] | Maximum [Member]	
Property, Plant and Equipment [Line Items]	
Property, Plant and Equipment, Useful Life	40 years

Property, Plant and Equipment (Details 2) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012 project	Dec. 31, 2011 project	Dec. 31, 2010 project
Property Plant And Equipment Disclosure [Abstract]			
Amounts capitalized less than one year after completion of drilling	$ 388	$ 482	$ 334
Amounts capitalized greater than one year after completion of drilling	229	222	323
Total deferred exploratory well costs	617	704	657
Projects that have Exploratory Well Costs that have been Capitalized for Period Greater than One Year, Number of Projects	6	5	7
Increase (Decrease) in Capitalized Exploratory Well Costs that are Pending Determination of Proved Reserves [Roll Forward]			
Beginning balance	704	657	829
Additions	731	670	329
Dry well expense	(143)	(268)	(83)
Transfers to development	(629)	(279)	(54)
Dispositions	(46)	(76)	(364)
Ending balance	$ 617	$ 704	$ 657

Consolidated Statements of Income (USD $) In Millions, except Per Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Revenues and other income:			
Sales and other operating revenues	$ 15,630	$ 14,603	$ 11,634
Sales to related parties	58	60	56
Income from equity method investments	370	462	344
Net gain on disposal of assets	127	103	766
Other income	36	54	73
Total revenues and other income	16,221	15,282	12,873
Costs and expenses:			
Cost of revenues (excludes items below)	5,219	6,225	4,786
Purchases from related parties	248	250	172
Depreciation, depletion and amortization	2,478	2,266	2,056
Impairments	371	310	447
General and administrative expenses	555	544	491
Other taxes	289	230	199
Exploration expenses	729	644	498
Total costs and expenses	9,889	10,469	8,649
Income from operations	6,332	4,813	4,224
Net interest and other	(219)	(107)	(75)
Loss on early extinguishment of debt	0	(279)	(92)
Income from continuing operations before income taxes	6,113	4,427	4,057
Provision for income taxes	4,531	2,720	2,175
Income from continuing operations	1,582	1,707	1,882
Discontinued operations	0	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568
Basic:			
Income from continuing operations (in dollars per share)	$ 2.24	$ 2.40	$ 2.65
Discontinued operations (in dollars per share)	$ 0.00	$ 1.75	$ 0.97
Net income (in dollars per share)	$ 2.24	$ 4.15	$ 3.62
Diluted:			
Income from continuing operations (in dollars per share)	$ 2.23	$ 2.39	$ 2.65
Discontinued operations (in dollars per share)	$ 0.00	$ 1.74	$ 0.96
Net income (in dollars per share)	$ 2.23	$ 4.13	$ 3.61
Dividends (in dollars per share)	$ 0.68	$ 0.80	$ 0.99
Weighted average shares:			
Basic	706	710	710
Diluted	710	714	712

Derivatives (Tables)

12 Months Ended
Dec. 31, 2012

Derivatives Disclosure [Abstract]

Derivatives as they appear on the Balance Sheet

The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheet as of December 31, 2012.

	December 31, 2012			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$ 18	$ —	$ 18	Other current assets
Interest rate	21	—	21	Other noncurrent assets
Total Designated Hedges	39	—	39	
Not Designated as Hedges				
Commodity	52	—	52	Other current assets
Total Not Designated as Hedges	52	—	52	
Total	$ 91	$ —	$ 91	

Effects of derivatives designated as fair value hedges

The following table summarizes the pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income.

		Gain (Loss)		
(In millions)	Income Statement Location	2012	2011	2010
Derivative				
Commodity	Sales and other operating revenues	$ —	$ —	$ (1)
Interest rate	Net interest and other	16	28	26
Interest rate	Loss on early extinguishment of debt	—	29	—
Foreign currency	Provision for income taxes	(1)	—	—
Hedged Item				
Commodity	Sales and other operating revenues	$ —	$ —	$ 1
Long-term debt	Net interest and other	(16)	(28)	(26)
Long-term debt	Loss on early extinguishment of debt	—	(29)	—
Accrued taxes	Provision for income taxes	1	—	—

Schedule of Notional Amounts of Outstanding Derivative Positions

In August 2012, we entered into crude oil derivatives related to a portion of our forecasted U.S. E&P crude oil sales through December 31, 2013. These commodity derivatives were not designated as hedges and are shown in the table below.

Remaining Term	Bbls per Day	Weighted Average Price per Bbl	Benchmark
Swaps			
January 2013 - December 2013	20,000	$96.29	West Texas Intermediate
January 2013 - December 2013	25,000	$109.19	Brent
Option Collars			
January 2013 - December 2013	15,000	$90.00 floor / $101.17 ceiling	West Texas Intermediate
January 2013 - December 2013	15,000	$100.00 floor / $116.30 ceiling	Brent

Incentive Based Compensation Plans (Details 5-Performance) (USD $) Share data in Millions, unless otherwise specified	3 Months Ended	12 Months Ended	
	Sep. 30, 2011	Dec. 31, 2012	Dec. 31, 2011
Performance Unit Disclosures [Abstract]			
Award instruments other than options performance unit target value		$ 1	
Award instruments other than options performance unit maximum value		2	
Award instruments other than options performance unit minimum value		0	
Award instruments other than options performance unit compensation expense		12,000,000	32,000,000
Award instruments other than options performance unit compensation expense accelerated			$ 14,000,000
Performance Unit Granted	15.0	12.7	
Performance Unit Awards Vesting Period	18 months	36 months	
Performance Unit Awards Vesting Period, Portion	30 months		

Consolidated Statements of Cash Flows (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Operating activities:			
Net income	$ 1,582	$ 2,946	$ 2,568
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations	0	(1,239)	(686)
Loss on early extinguishment of debt	0	279	92
Deferred income taxes	(210)	(182)	(489)
Depreciation, depletion and amortization	2,478	2,266	2,056
Impairments	371	310	447
Pension and other postretirement benefits, net	(31)	64	31
Exploratory dry well costs and unproved property impairments	457	357	225
Net gain on disposal of assets	(127)	(103)	(766)
Equity method investments, net	11	47	56
Changes in:			
Current receivables	(499)	8	(409)
Inventories	(34)	33	(71)
Current accounts payable and accrued liabilities	96	485	1,018
All other operating, net	(77)	163	122
Net cash provided by continuing operations	4,017	5,434	4,194
Net cash provided by discontinued operations	0	1,090	1,676
Net cash provided by operating activities	4,017	6,524	5,870
Investing activities:			
Acquisitions, net of cash acquired	(1,033)	(4,470)	0
Additions to property, plant and equipment	(4,940)	(3,295)	(3,536)
Disposal of assets	467	518	1,368
Investments - return of capital	57	59	58
Investing activities of discontinued operations	0	(493)	(464)
All other investing, net	10	14	(47)
Net cash used in investing activities	(5,439)	(7,667)	(2,621)
Financing activities:			
Commercial paper, net	200	0	0
Borrowings	1,997	0	0
Debt issuance costs	(21)	0	0
Debt repayments	(145)	(2,877)	(653)
Purchases of common stock	0	(300)	0
Dividends paid	(480)	(567)	(704)
Financing activities of discontinued operations	0	2,916	(12)
Distribution in spin-off	0	(1,622)	0
All other financing, net	49	155	14
Net cash provided by (used in) financing activities	1,600	(2,295)	(1,355)

Effect of exchange rate changes on cash	13	(20)	0
Net increase (decrease) in cash and cash equivalents	191	(3,458)	1,894
Cash and cash equivalents at beginning of period	493	3,951	2,057
Cash and cash equivalents at end of period	$ 684	$ 493	$ 3,951

Incentive Based Compensation (Details 3 - Stock Options) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended Dec. 31, 2012
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Outstanding Under Option	19,536,965
Weighted Average Remaining Contractual Life	6 years
Weighted Average Exercise Price - Outstanding Shares	$ 26.19
Number of Shares Exercisable Under Option	14,263,424
Weighted Average Exercise Price - Exercisable Shares	$ 25.41
Share-based Compensation Arrangement by Share-based Payment Award, Options, Outstanding, Intrinsic Value	$ 122
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercisable, Intrinsic Value	105
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercisable, Weighted Average Remaining Contractual Term	5 years
Share-based Compensation Arrangement by Share-based Payment Award, Options, Vested and Expected to Vest, Exercisable, Number	19,466,855
Share-based Compensation Arrangement by Share-based Payment Award, Options, Vested and Expected to Vest, Exercisable, Weighted Average Exercise Price	$ 26.18
Share-based Compensation Arrangement by Share-based Payment Award, Options, Vested and Expected to Vest, Outstanding, Weighted Average Remaining Contractual Term	6 years
Share-based Compensation Arrangement by Share-based Payment Award, Options, Vested and Expected to Vest, Exercisable, Aggregate Intrinsic Value	122
Employee Service Share-based Compensation, Nonvested Awards, Total Compensation Cost Not yet Recognized	$ 22
Employee Service Share-based Compensation, Nonvested Awards, Total Compensation Cost Not yet Recognized, Period for Recognition	1 year
$ 7.99-12.75	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Outstanding Under Option	429,685
Weighted Average Remaining Contractual Life	1 year
Weighted Average Exercise Price - Outstanding Shares	$ 10.06
Number of Shares Exercisable Under Option	429,685
Weighted Average Exercise Price - Exercisable Shares	$ 10.06
12.76-16.81	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Outstanding Under Option	2,307,526
Weighted Average Remaining Contractual Life	4 years
Weighted Average Exercise Price - Outstanding Shares	$ 15.18

Number of Shares Exercisable Under Option	2,307,526
Weighted Average Exercise Price - Exercisable Shares	$ 15.18

16.82-23.20

Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]

Number of Shares Outstanding Under Option	5,409,048
Weighted Average Remaining Contractual Life	7 years
Weighted Average Exercise Price - Outstanding Shares	$ 18.60
Number of Shares Exercisable Under Option	4,105,057
Weighted Average Exercise Price - Exercisable Shares	$ 18.55

23.21-29.24

Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]

Number of Shares Outstanding Under Option	2,031,690
Weighted Average Remaining Contractual Life	5 years
Weighted Average Exercise Price - Outstanding Shares	$ 24.63
Number of Shares Exercisable Under Option	1,599,222
Weighted Average Exercise Price - Exercisable Shares	$ 23.79

29.25-36.03

Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]

Number of Shares Outstanding Under Option	6,809,564
Weighted Average Remaining Contractual Life	6 years
Weighted Average Exercise Price - Outstanding Shares	$ 32.93
Number of Shares Exercisable Under Option	3,272,482
Weighted Average Exercise Price - Exercisable Shares	$ 32.50

36.04-46.41

Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]

Number of Shares Outstanding Under Option	2,549,452
Weighted Average Remaining Contractual Life	6 years
Weighted Average Exercise Price - Outstanding Shares	$ 38.25
Number of Shares Exercisable Under Option	2,549,452
Weighted Average Exercise Price - Exercisable Shares	$ 38.25

Income per Common Share (Details) (USD $) In Millions, except Per Share data, unless otherwise specified	**12 Months Ended**		
	Dec. 31, 2012	**Dec. 31, 2011**	**Dec. 31, 2010**
Per Share Data			
Income from continuing operations	$ 1,582	$ 1,707	$ 1,882
Discontinued operations	0	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568
Basic	706	710	710
Effect of dilutive securities	4	4	2
Diluted	710	714	712
Basic:			
Income from continuing operations (in dollars per share)	$ 2.24	$ 2.40	$ 2.65
Discontinued operations	$ 0.00	$ 1.75	$ 0.97
Net income (in dollars per share)	$ 2.24	$ 4.15	$ 3.62
Diluted:			
Income from continuing operations (in dollars per share)	$ 2.23	$ 2.39	$ 2.65
Discontinued operations (in dollars per share)	$ 0.00	$ 1.74	$ 0.96
Net income (in dollars per share)	$ 2.23	$ 4.13	$ 3.61
Antidilutive securities excluded from computation of earnings per share	10	7	13

Commitments and Contingencies (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2012 Clairton [Member]	Dec. 31, 2012 Ireland [Member]	Dec. 31, 2012 Other Guarantee [Member]	Dec. 31, 2012 Water abatement Oil Sands [Member]	Jun. 30, 2011 Water abatement Oil Sands [Member]
Guarantor Obligations [Line Items]							
Guarantor Obligations, Maximum Exposure, Undiscounted			$ 110	$ 40	$ 94		
Commitments to acquire property, plant and equipment	949	615					
Site Contingency, Accrual, Undiscounted Amount						$ 39	$ 64

Dispositions (Tables)	12 Months Ended Dec. 31, 2012
Dispositions Disclosure [Abstract]	
Discontinued Operations Table	Assets held for sale in the December 31, 2012 consolidated balance sheet were related to the Neptune gas plant and Alaska dispositions that were pending at that date and included:

(In millions)

Other current assets	$	50
Other noncurrent assets		248
Total assets	$	298
Deferred credits and other liabilities		83
Total liabilities	$	83

Other Items (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Net Interest and Other Financing [Abstract]			
Interest income	$ 13	$ 12	$ 11
Interest expense(a)	(300) [1]	(281) [1]	(375) [1]
Income on interest rate swaps	7	10	26
Interest capitalized	68	151	297
Total interest	(212)	(108)	(41)
Net foreign currency gains (losses)	4	24	(21)
Write off of contingent proceeds	0	(7)	(15)
Other	(11)	(16)	2
Total other	(7)	1	(34)
Net interest and other	(219)	(107)	(75)
Interest payments made on our behalf	1	10	16
Aggregate foreign currency gains losses [Abstract]			
Net interest and other	4	24	(21)
Provision for income taxes	80	(57)	(1)
Aggregate foreign currency gains (losses)	$ 84	$ (33)	$ (22)

[1] Excludes $1 million, $10 million and $16 million paid by United States Steel in 2012, 2011 and 2010 on assumed debt.

Fair Value Measurements	**12 Months Ended Dec. 31, 2012**
Fair Value Disclosures [Abstract]	
Fair Value Measurements	

Fair Value Measurements

Fair values – Recurring

The following table presents assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2012 by fair value hierarchy level.

	December 31, 2012									
(In millions)	Level 1		Level 2		Level 3		Collateral		Total	
Derivative instruments, assets										
Commodity	$	—	$	52	$	—	$	1	$	53
Interest rate		—		21		—		—		21
Foreign currency		—		18		—		—		18
Derivative instruments, assets	$	—	$	91	$	—	$	1	$	92

As of December 31, 2011, balances related to interest rate swaps accounted for at fair value on a recurring basis were noncurrent assets of $5 million measured at fair value using actionable broker quotes which are Level 2 inputs. There were no other significant recurring fair value measurements as of December 31, 2011.

Commodity swaps in Level 2 are measured at fair value with a market approach using prices obtained from exchanges or pricing services, which have been corroborated with data from active markets for similar assets or liabilities. Commodity options in Level 2 are valued using the Black-Scholes Model. Inputs to this model include prices as noted above, discount factors, and implied market volatility. The inputs to this fair value measurement are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments. Collateral deposits related to commodity derivatives are in broker accounts covered by master netting agreements.

Interest rate swaps are measured at fair value with a market approach using actionable broker quotes which are Level 2 inputs. Foreign currency forwards are measured at fair value with a market approach using third-party pricing services, such as Bloomberg L.P., which have been corroborated with data from active markets for similar assets or liabilities, and are Level 2 inputs.

Fair values – Nonrecurring

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	2012				2011				2010			
(In millions)	Fair Value		Impairment		Fair Value		Impairment		Fair Value		Impairment	
Long-lived assets held for use	$	16	$	371	$	226	$	285	$	147	$	447
Long-lived assets held for sale		—		—		—		—		85		64

Intangible assets	—	—	—	25	—	—
Equity method investments	—	—	—	—	—	25

Long-lived assets held for use – All long-lived assets held for use that were impaired in 2012, 2011 and 2010 were held by our E&P segment. The fair values of each discussed below were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement included reserve and production estimates made by our reservoir engineers, estimated commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

During early 2012, production rates from the Ozona development in the Gulf of Mexico declined significantly and have remained below initial expectations. Accordingly, our reserve engineers performed evaluations of our future production as well as our reserves and an impairment was recorded in the first quarter of 2012. As the development produced toward abandonment pressures, further downward revisions of reserves were taken, resulting in a fair value measurement of $6 million by year end for an aggregate impairment of $289 million in 2012.

In the fourth quarter of 2012, declining natural gas prices prompted lower production expectations and reductions in estimated reserves related to our Powder River Basin asset. This resulted in an impairment of $73 million to reach the $6 million fair value of this asset. Additionally, in March 2010, we completed a reservoir study which resulted in a portion of our Powder River Basin asset being removed from plans for future development. At that time, the asset's fair value was measured at $144 million and an impairment of $423 million was recorded.

In May 2011, significant water production and reservoir pressure declines occurred at our Droshky development in the Gulf of Mexico. Plans for a waterflood were canceled and the field will be produced to abandonment pressures, which are expected in the first half of 2013. Consequently, proved reserves were reduced by 3.4 million boe and a $273 million impairment of this asset to its $226 million fair value was recorded in 2011.

Other impairments of long-lived assets held for use by our E&P segment in 2012, 2011 and 2010 were a result of reduced drilling expectations, reductions of estimated reserves or declining natural gas prices.

Intangible assets – In the second quarter of 2011, our outlook for U.S. natural gas prices made it unlikely that sufficient U.S. demand for LNG would materialize by 2021, which is when the rights lapse under our arrangements at the Elba Island, Georgia regasification facility. Using an income approach based upon internal estimates of gas prices and future deliveries, which are Level 3 inputs, we determined that the contract had no remaining fair value and recorded a full impairment of this intangible asset held in our IG segment.

Long-lived assets held for sale – In the fourth quarter of 2010, due to the pending sale of our E&P segment's non-operated interest in the Gudrun field development, located offshore Norway, we recorded a loss for this asset held for sale. The fair value was based upon the transaction, which is a Level 3 market input.

Equity method investments – In the third quarter of 2010, we fully impaired our IG segment's equity method investment in an entity engaged in gas-to-fuels related technology. This investment was determined to have sustained an other than temporary loss in value. The fair value was measured with an income approach using internally developed estimates of future cash flows. These cash flows are Level 3 inputs.

Fair values – Financial instruments

Our current assets and liabilities include financial instruments, the most significant of which are accounts receivables, commercial paper and payables. We believe the carrying values of accounts receivable, commercial paper and payables approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding trade accounts receivable, commercial paper, payables and derivative financial instruments and their reported fair value, by individual balance sheet line item at December 31, 2012 and 2011.

	December 31,			
	2012		2011	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 2	$ 2	$ 146	$ 148
Other noncurrent assets	189	186	68	68
Total financial assets	191	188	214	216
Financial liabilities				
Other current liabilities	13	13	—	—
Long-term debt, including current portion[(a)]	7,610	6,642	5,479	4,753
Deferred credits and other liabilities	94	94	36	38
Total financial liabilities	$ 7,717	$ 6,749	$ 5,515	$ 4,791

(a) Excludes capital leases.

Fair values of our remaining financial assets included in other current assets and other noncurrent assets, and of our financial liabilities included in other current liabilities and deferred credits and other liabilities are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

Most of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions, is used to measure the fair value of such debt. Because these quotes cannot be independently verified to an active market they are considered Level 3 inputs. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

Income per Common Share (Tables)

12 Months Ended Dec. 31, 2012

Per Share Data

Schedule of Earnings Per Share, Basic and Diluted

Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive.

	2012		2011		2010	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,582	$ 1,582	$ 1,707	$ 1,707	$ 1,882	$ 1,882
Discontinued operations	—	—	1,239	1,239	686	686
Net income	$ 1,582	$ 1,582	$ 2,946	$ 2,946	$ 2,568	$ 2,568
Weighted average common shares outstanding	706	706	710	710	710	710
Effect of dilutive securities	—	4	—	4	—	2
Weighted average common shares, including dilutive effect	706	710	710	714	710	712
Per share:						
Income from continuing operations	$ 2.24	$ 2.23	$ 2.40	$ 2.39	$ 2.65	$ 2.65
Discontinued operations	$ —	$ —	$ 1.75	$ 1.74	$ 0.97	$ 0.96
Net income	$ 2.24	$ 2.23	$ 4.15	$ 4.13	$ 3.62	$ 3.61

Leases (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2012	 Dec. 31, 2011	 Dec. 31, 2010
Operating Leases, Future Minimum Payments Due, Fiscal Year Maturity [Abstract]			
Year 1 Operating	$ 42		
Year 2 Operating	36		
Year 3 Operating	33		
Year 4 Operating	29		
Year 5 Operating	21		
Later years, Operating Leases	49		
Sublease rentals	(2)		
Operating Leases, Future Minimum Payments Due	208		
Capital Leases, Future Minimum Payments Due, Fiscal Year Maturity [Abstract]			
Year 1 Capital	1		
Year 2 Capital	1		
Year 3 Capital	1		
Year 4 Capital	1		
Year 5 Capital	1		
Later years, Capital Leases	24		
Capital Leases Sublease Rentals	0		
Capital Leases, Future Minimum Payments Due	29		
Less imputed interest costs	(18)		
Capital Leases, Future Minimum Payments, Present Value of Net Minimum Payments	11		
Operating Leases, Rent Expense, Net [Abstract]			
Operating Leases, Rent Expense	74	74	77
Lease Payments Made On Our Behalf			$ 16

Debt	12 Months Ended Dec. 31, 2012
Debt Disclosure [Abstract]	
Debt	**Debt**

Short-term debt

As of December 31, 2012, we had no borrowings against our revolving credit facility, as described below, and we had $200 million in commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

In April 2012, we terminated our $3.0 billion five-year revolving credit facility and replaced it with a new $2.5 billion unsecured five-year revolving credit facility (the "Credit Facility"). The Credit Facility matures in April 2017, but allows us to request two one-year extensions. It contains an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and includes sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million, respectively. Fees on the unused commitment of each lender range from 10 basis points to 25 basis points depending on our credit ratings. Borrowings under the Credit Facility bear interest, at our option, at either (a) an adjusted LIBOR rate plus a margin ranging from 87.5 basis points to 162.5 basis points per year depending on our credit ratings or (b) the Base Rate plus a margin ranging from 0.0 basis points to 62.5 basis points depending on our credit ratings. Base Rate is defined as a per annum rate equal to the greatest of (a) the prime rate, (b) the federal funds rate plus one-half of one percent and (c) LIBOR for a one-month interest period plus one percent.

The agreement contains a covenant that requires our ratio of total debt to total capitalization not to exceed 65 percent as of the last day of each fiscal quarter. If an event of default occurs, the lenders may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility.

Long-term debt

The following table details our long-term debt:

	December 31,	
(In millions)	2012	2011
Senior unsecured notes:		
9.375% notes due 2012	$ —	$ 53
9.125% notes due 2013	114	114
0.900% notes due 2015[(a)]	1,000	—
6.000% notes due 2017[(a)]	682	682
5.900% notes due 2018[(a)]	854	854
7.500% notes due 2019[(a)]	228	228
2.800% notes due 2022[(a)]	1,000	—
9.375% notes due 2022	32	32
Series A notes due 2022	3	3
8.500% notes due 2023	70	70
8.125% notes due 2023	131	131
6.800% notes due 2032[(a)]	550	550
6.600% notes due 2037	750	750
Capital leases:		

Capital lease obligation due 2012	—	9
Sale-leaseback obligation due 2012	—	11
Capital lease obligation of consolidated subsidiary due 2013 – 2049	11	11
Other obligations:		
4.550% promissory note, semi-annual payments due 2013 – 2015	204	272
5.375% obligation relating to revenue bonds due 2013	—	23
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Other	35	—
Total[b]	6,664	4,793
Unamortized discount	(11)	(10)
Fair value adjustments[c]	43	32
Amounts due within one year	(184)	(141)
Total long-term debt due after one year	$ 6,512	$ 4,674

[a] These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

[b] In the event of a change in control, as defined in the related agreements, debt obligations totaling $385 million at December 31, 2012, may be declared immediately due and payable.

[c] See Note 15 for information on interest rate swaps.

On October 29, 2012, we issued $1 billion aggregate principal amount of senior notes bearing interest at 0.9 percent with a maturity date of November 1, 2015 and $1 billion aggregate principal amount of senior notes bearing interest at 2.8 percent with a maturity date of November 1, 2022. Interest on the senior notes is payable semi-annually beginning May 1, 2013. The proceeds were used to pay off commercial paper and for general corporate purposes.

In the second quarter of 2012, we retired the remaining $23 million principal amount of our 5.375 percent revenue bonds due December 2013. No gain or loss was recorded on this early extinguishment of debt.

In February and March 2011, we retired $2,498 million aggregate face amount of debt at a weighted average price equal to 112 percent of face value. A $279 million loss on early extinguishment of debt was recognized in the first quarter of 2011. The loss includes related deferred financing and premium costs partially offset by the gain on settled interest rate swaps.

The following table shows five years of long-term debt payments:

(In millions)	
2013	$ 184
2014	71
2015	1,070
2016	3
2017	685

Income Taxes (Details 3) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Unrecognized Tax Benefit Rollforward [Abstract]			
Unrecognized Tax Benefits, Beginning Balance	$ 157	$ 103	$ 75
Additions for tax positions related to the current year	0	4	28
Reductions for tax positions related to the current year	0	0	(1)
Additions for tax positions of prior years	81	87	25
Reductions for tax positions of prior years	(67)	(29)	(12)
Settlements	(72)	(8)	(12)
Statute of limitations	(1)	0	0
Unrecognized Tax Benefits, Ending Balance	98	157	103
Unrecognized Tax Benefits That Would Impact Effective Tax Rate	92		
Significant Change In Unrecognized Tax Benefits Is Reasonably Possible Amount Of Unrecorded Benefit	16		
Unrecognized Tax Benefits, Income Tax Penalties and Interest Expense [Abstract]			
Unrecognized Tax Benefits, Income Tax Penalties and Interest Expense	4	13	5
Unrecognized Tax Benefits, Income Tax Penalties and Interest Accrued [Abstract]			
Unrecognized Tax Benefits, Income Tax Penalties and Interest Accrued	24	27	
Foreign Source Income [Abstract]			
Foreign Source Income	6,365	4,869	4,563
Undistributed Income of Certain Consolidated Foreign Subsidiaries [Abstract]			
Undistributed Income Of Certain Consolidated Foreign Subsidiaries	571		
Income Tax Expense If Not Permanently Reinvested	$ 200		

Consolidated Statements of Stockholders Equity (USD $) In Millions, unless otherwise specified	Total USD ($)	Preferred Stock [Member]	Common Stock [Member] USD ($)	Common Stock Securities Exchangable [Member]	Treasury Stock [Member] USD ($)	Additional Paid-in Capital [Member] USD ($)	Retained Earnings [Member] USD ($)	Accumulated Other Comprehensive Income (Loss) [Member] USD ($)	Noncontrolling Interest [Member] USD ($)
Beginning Balance at Dec. 31, 2009	$ 21,910		$ 769		$ (2,706)	$ 6,738	$ 18,043	$ (934)	
Shares, Issued Beginning Balance at Dec. 31, 2009		1	769	1	61				
Increase (Decrease) in Stockholders' Equity [Roll Forward]									
Shares issued - stock based compensation	34				46	(12)			
Shares exchanged			1			(1)			
Shares repurchased	(5)				(5)				
Stock-based compensation	31					31			
Net income	2,568						2,568		
Other comprehensive income (loss)	(63)							(63)	
Dividends paid	(704)						(704)		
Shares issued - stock based compensation					1				
Shares exchanged		1	1	1					
Ending Balance at Dec. 31, 2010	23,771		770		(2,665)	6,756	19,907	(997)	
Shares, Issued Ending Balance at Dec. 31, 2010		0	770		60				
Increase (Decrease) in Stockholders' Equity [Roll Forward]									
Shares issued - stock based compensation	172				257	(85)			
Shares repurchased	(308)				(308)				
Stock-based compensation	4					4			
Net income	2,946						2,946		
Other comprehensive income (loss)	40							40	
Dividends paid	(567)						(567)		
Purchase of subsidiary shares from non-controlling interest	7								7
Spin-off of downstream business	(8,906)					5	(9,498)	587	
Other	(8,906)					5	(9,498)	587	
Shares issued - stock based compensation					6				
Shares repurchased	12				12				
Ending Balance at Dec. 31, 2011	17,159		770		(2,716)	6,680	12,788	(370)	7
Shares, Issued Ending Balance at Dec. 31, 2011			770		66				
Increase (Decrease) in Stockholders' Equity [Roll Forward]									
Shares issued - stock based compensation	89				164	(75)			

Shares repurchased	(8)		(8)				
Stock-based compensation	22			22			
Net income	1,582				1,582		
Other comprehensive income (loss)	(63)					(63)	
Dividends paid	(480)				(480)		
Purchase of subsidiary shares from non-controlling interest	(7)						(7)
Shares issued - stock based compensation			3				
Shares repurchased			0				
Other	(11)			(11)			
Ending Balance at Dec. 31, 2012	$ 18,283	$ 770	$ (2,560)	$ 6,616	$ 13,890	$ (433)	
Shares, Issued Ending Balance at Dec. 31, 2012		770	63				

Consolidated Statements of Comprehensive Income (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Statement of Other Comprehensive Income [Abstract]			
Net income	$ 1,582	$ 2,946	$ 2,568
Postretirement and postemployment plans			
Change in actuarial loss and other	(97)	16 [1]	(76)
Income tax benefit (provision) on postretirement and postemployment plans	35	20 [1]	7
Postretirement and postemployment plans, net of tax	(62)	36 [1]	(69)
Derivative hedges			
Net unrecognized gain	1	9 [1]	5
Income tax benefit (provision) on derivative hedges	0	(4) [1]	1
Derivative hedges, net of tax	1	5 [1]	6
Foreign currency translation and other			
Unrealized gain (loss)	1	(1) [1]	0
Income tax provision on foreign currency translation and other	(3)	0 [1]	0
Foreign currency translation and other, net of tax	(2)	(1) [1]	0
Other comprehensive income (loss)	(63)	40 [1]	(63)
Comprehensive income	$ 1,519	$ 2,986 [1]	$ 2,505

[1] See Note 1 – Summary of Principal Accounting Policies – Revision for additional information.

Income Taxes	12 Months Ended Dec. 31, 2012
Income Taxes Disclosure [Abstract]	
Income Taxes	

Income Taxes

Income tax provisions (benefits) were:

	2012			2011			2010		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ (80)	$ 233	$ 153	$ (210)	$ (206)	$ (416)	$ (279)	$ (267)	$ (546)
State and local	(23)	47	24	24	82	106	2	(10)	(8)
Foreign	4,844	(490)	4,354	3,088	(58)	3,030	2,941	(212)	2,729
Total	$ 4,741	$ (210)	$4,531	$ 2,902	$ (182)	$2,720	$ 2,664	$ (489)	$2,175

A reconciliation of the federal statutory income tax rate applied to income from continuing operations before income taxes to the provision for income taxes follows:

	2012	2011	2010
Statutory rate applied to income from continuing operations before income taxes	35%	35%	35 %
Effects of foreign operations, including foreign tax credits	18	6	20
Change in permanent reinvestment assertion	—	5	—
Adjustments to valuation allowances	21	14	(2)
Tax law changes	—	1	1
Effective income tax rate on continuing operations	74%	61%	54 %

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in "Corporate and other unallocated items" shown in Note 8.

Effects of foreign operations – The effects of foreign operations on our effective tax rate increased in 2012 as compared to 2011, primarily due to the resumption of sales of Libyan production in 2012, where the statutory tax rate is in excess of 90 percent.

Change in permanent reinvestment assertion – In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognizing deferred U.S. tax on previously undistributed earnings.

Adjustments to valuation allowances – In 2012 and 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in those years.

Tax law changes – On July 17, 2012, the U.K. enacted Finance Bill 2012 which restricted relief on decommissioning charges and reduced the main corporate tax rate. There were no changes to the rate of corporation tax or the supplementary corporation tax for U.K. ring-fenced activities in the oil and gas sector. This legislation did not have a material impact on our consolidated financial statements. In July

2011, the U.K. enacted Finance Bill 2011 which increased the rate of the supplementary charge levied on profits from U.K. oil and gas production from 20 percent to 32 percent. As a result of this legislation, we recorded deferred tax expense of $10 million in 2011.

On May 25, 2011, Michigan enacted legislation that replaced the Michigan Business Tax ("MBT") with a corporate income tax ("CIT"), effective January 1, 2012. The CIT legislation eliminated the "book-tax difference deduction" that was provided under the MBT to mitigate the net increase in a taxpayer's deferred tax liability resulting when Michigan moved from the Single Business Tax, a non-income tax, to the MBT, an income tax, on July 12, 2007. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relates to discontinued operations. As a result of the new CIT legislation, we recorded deferred tax expense of $32 million in the second quarter of 2011.

The Patient Protection and Affordable Care Act ("PPACA") and the Health Care and Education Reconciliation Act of 2010 ("HCERA"), (together, the "Acts") were signed in to law in March 2010. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D. The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the "MPDIMA"). Under the MPDIMA, the federal subsidy did not reduce our income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually. Beginning in 2013, under the Acts, our income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relates to discontinued operations. As a result, we recorded deferred tax expense of $45 million in the first quarter of 2010 for the write-off of deferred tax assets to reflect the change in the tax treatment of the federal subsidy.

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(In millions)	2012	2011[a]
Deferred tax assets:		
Employee benefits	$ 510	$ 455
Operating loss carryforwards	368	354
Foreign tax credits	4,351	3,005
Other	121	95
Valuation allowances:		
Federal	(2,067)	(790)
State, net of federal benefit	(60)	(40)
Foreign	(210)	(194)
Total deferred tax assets	3,013	2,885
Deferred tax liabilities:		
Property, plant and equipment	3,691	3,404
Investments in subsidiaries and affiliates	840	1,216
Other	12	41
Total deferred tax liabilities	4,543	4,661
Net deferred tax liabilities	$ 1,530	$ 1,776

[a] Certain 2011 amounts were reclassified to conform to the current period's presentation.

Operating loss carryforwards – At December 31, 2012, our operating loss carryforwards include $811 million of Canadian operating loss carryforwards that expire from 2013 through 2032 and $216 million of Indonesian operating loss carryforwards that do not have expiration dates. State operating loss carryforwards of $1,363 million expire in 2013 through 2031.

Valuation allowances – The ability to realize the benefit of foreign tax credits is based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the years that such credits may be claimed. Federal valuation allowances increased $1,277 million in 2012, increased $585 million in 2011, and decreased $74 million in 2010 due to changes in the expected realizability of foreign tax credits.

Foreign valuation allowances increased $16 million in 2012, primarily due to deferred tax assets generated in the Kurdistan Region of Iraq and Angola. Foreign valuation allowances increased $52 million and $40 million in 2011 and 2010, primarily due to net operating loss carryforwards generated in Indonesia.

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(In millions)	2012	2011
Assets:		
Other current assets	$ 57	$ 99
Other noncurrent assets	849	674
Liabilities:		
Other current liabilities	4	5
Noncurrent deferred tax liabilities	2,432	2,544
Net deferred tax liabilities	$ 1,530	$ 1,776

We are continuously undergoing examination of our U.S. federal income tax returns by the IRS. Such audits have been completed through the 2009 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities.

As of December 31, 2012, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[a]	2005-2011
Canada	2008-2011
Equatorial Guinea	2007-2011
Libya	2006-2011
Norway	2008-2011
United Kingdom	2008-2011

[a] Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2012	2011	2010
Beginning balance	$ 157	$ 103	$ 75
Additions for tax positions related to the current year	—	4	28
Reductions for tax positions related to the current year	—	—	(1)
Additions for tax positions of prior years	81	87	25
Reductions for tax positions of prior years	(67)	(29)	(12)
Settlements	(72)	(8)	(12)
Statute of limitations	(1)	—	—

Ending balance	$ 98	$ 157	$ 103

If the unrecognized tax benefits as of December 31, 2012 were recognized, $92 million would affect our effective income tax rate. There were $16 million of uncertain tax positions as of December 31, 2012 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly increase or decrease during the next twelve months.

Interest and penalties are recorded as part of the tax provision and were $4 million, $13 million and $5 million related to unrecognized tax benefits in 2012, 2011 and 2010. As of December 31, 2012 and 2011, $24 million and $27 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $6,365 million, $4,869 million and $4,563 million in 2012, 2011 and 2010.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2012 amounted to $571 million for which no U.S. deferred income tax provision has been recorded because we intend to permanently reinvest such income in our foreign operations. If such income was not permanently reinvested, income tax expense of approximately $200 million would be recorded, not including potential utilization of foreign tax credits.

Incentive Based Compensation Plans (Details 2) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Number of Shares			
Beginning year stock option awards	21,370,715		
Granted stock option awards	1,858,872		
Exercised stock option awards	(2,795,612)		
Canceled stock option awards	(897,010)		
End of year stock option awards	19,536,965	21,370,715	
Weighted Average Exercise price			
Beginning year weighted average exercise price	$ 24.41		
Granted weighted average exercise price	$ 33.52	$ 32.30	$ 30.00
Exercises weighted average exercise price	$ 16.46		
Canceled weighted average exercise price	$ 29.29		
End of year weighted average exercise price	$ 26.19	$ 24.41	
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercises in Period, Total Intrinsic Value	$ 40	$ 59	$ 8

Defined Benefit Postretirement Plans and Defined Contribution Plan (Details 6) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Defined Benefit Plan Estimated Future Benefit Payments [Line Items]			
Defined Benefit Plan, Estimated Future Employer Contributions in Next Fiscal Year	$ 64		
Cash Contributions Expected To Be Paid From General Assets Unfunded Plan	16		
Cash Contributions Expected To Be Paid From General Assets Postretirement Plan	18		
Defined Benefit Plan, Information about Plan Assets [Abstract]			
Defined Contribution Plan, Cost Recognized	25	21	20
United States Pension Plans of US Entity, Defined Benefit [Member]			
Defined Benefit Plan Estimated Future Benefit Payments [Line Items]			
2013	113		
2014	114		
2015	114		
2016	112		
2017	114		
2018 through 2022	530		
Foreign Pension Plans, Defined Benefit [Member]			
Defined Benefit Plan Estimated Future Benefit Payments [Line Items]			
2013	12		
2014	14		
2015	16		
2016	18		
2017	20		
2018 through 2022	109		
Other Postretirement Benefit Plans, Defined Benefit [Member]			
Defined Benefit Plan Estimated Future Benefit Payments [Line Items]			
2013	18		
2014	19		
2015	20		
2016	20		
2017	20		
2018 through 2022	$ 101		

Document and Entity Information (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Jan. 31, 2013	Jun. 29, 2012
Document and Entity Information [Abstract]			
Document Type	10-K		
Document Period End Date	Dec. 31, 2012		
Document Fiscal Period Focus	FY		
Document Fiscal Year Focus	2012		
Amendment Flag	false		
Entity Registrant Name	Marathon Oil Corp		
Entity Central Index Key	0000101778		
Entity Current Reporting Status	Yes		
Entity Voluntary Filers	No		
Current Fiscal Year End Date	--12-31		
Entity Filer Category	Large Accelerated Filer		
Entity Well Known Seasoned Issuer	Yes		
Entity Common Stock Shares Outstanding		707,709,281	
Entity Public Float			$ 17,991

Inventories	**12 Months Ended Dec. 31, 2012**
Inventory Disclosure [Abstract]	
Inventories	

Inventories

Inventories are carried at the lower of cost or market value. The LIFO method accounted for 6 percent and 23 percent of total inventory value at December 31, 2012 and 2011. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2012 and 2011 by $29 million and $74 million.

	December 31,	
(In millions)	2012	2011
Liquid hydrocarbons, natural gas and bitumen	$ 73	$ 147
Supplies and sundry items	288	214
Inventories at cost	$ 361	$ 361

Derivatives (Details 3-IS & OCI) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Sales and Other Operating Revenues [Member] | Commodity [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	$ 0	$ 0	$ (1)
Change in unrealized gain (loss) on hedged item in fair value hedge	0	0	1
Net interest and other [Member] | Interest rate [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	16	28	26
Net interest and other [Member] | Long-term Debt [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Change in unrealized gain (loss) on hedged item in fair value hedge	(16)	(28)	(26)
Loss On Early Extinguishment Of Debt [Member] | Interest rate [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	0	29	0
Loss On Early Extinguishment Of Debt [Member] | Long-term Debt [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Change in unrealized gain (loss) on hedged item in fair value hedge	0	(29)	0
Provision For Income Taxes [Member] | Foreign Exchange Contract [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	(1)	0	0
Provision For Income Taxes [Member] | Accrued Taxes [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Change in unrealized gain (loss) on hedged item in fair value hedge	$ 1	$ 0	$ 0

Consolidated Balance Sheets (USD $) In Millions, unless otherwise specified	Dec. 31, 2012	Dec. 31, 2011
Current assets:		
Cash and cash equivalents	$ 684	$ 493
Receivables	2,389	1,917
Receivables from related parties	27	35
Inventories	361	361
Other current assets	301	418
Total current assets	3,762	3,224
Equity method investments	1,279	1,383
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $19,266 and $17,248	28,272	25,324
Goodwill	525	536
Other noncurrent assets	1,468	904
Total assets	35,306	31,371
Current liabilities:		
Commercial paper	200	0
Accounts payable	2,285	1,864
Payables to related parties	20	18
Payroll and benefits payable	217	193
Accrued taxes	1,987	2,015
Other current liabilities	188	163
Long-term debt due within one year	184	141
Total current liabilities	5,081	4,394
Long-term debt	6,512	4,674
Deferred tax liabilities	2,432	2,544
Defined benefit postretirement plan obligations	856	789
Asset retirement obligations	1,749	1,510
Deferred credits and other liabilities	393	301
Total liabilities	17,023	14,212
Commitments and contingencies		
Stockholders' Equity		
Preferred stock no shares issued or outstanding (no par value, 26 million shares authorized)	0	0
Common stock issued - 770 million and 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Common stock, securities exchangeable into common stock - no shares issued or outstanding (no par value, 29 million shares authorized)	0	0
Common stock, held in treasury, at cost – 63 million and 66 million shares	(2,560)	(2,716)
Additional paid-in capital	6,616	6,680
Retained earnings	13,890	12,788
Accumulated other comprehensive loss	(433)	(370)
Total equity of Marathon Oil stockholders	18,283	17,152

Noncontrolling interest	0	7
Total equity	18,283	17,159
Total liabilities and equity	$ 35,306	$ 31,371

Acquisitions	12 Months Ended Dec. 31, 2012
Significant Acquisitions Disclosure [Abstract]	
Acquisitions	

Acquisitions

During 2012 and 2011, our significant business combinations related to properties acquired by our E&P segment in the Eagle Ford shale in south Texas. The pro forma impact of these transactions, individually and in the aggregate, is not material to our consolidated statements of income for any periods presented.

The fair values of assets acquired and liabilities assumed in each of these business combinations were measured primarily using an income approach, specifically utilizing a discounted cash flow analysis. The estimated fair values were based on significant inputs not observable in the market, and therefore represent Level 3 measurements. Significant inputs included estimated reserve volumes, the expected future production profile, estimated commodity prices and assumptions regarding future operating and development costs. The discount rates used in the discounted cash flow analyses were approximately 10 percent for the 2012 transactions and 11 percent for the 2011 transaction.

2012

We acquired approximately 25,000 net acres in the core of the Eagle Ford shale during 2012. The largest transactions were the acquisitions of Paloma Partners II, LLC, which closed August 1, 2012 for cash consideration of $768 million, and an acquisition of proved and unproved properties that closed on November 1, 2012 for cash consideration of $232 million. These transactions were accounted for as business combinations.

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

	Acquisition Date	
(In millions)	August 1, 2012	November 1, 2012
Current assets:		
Cash	$ 8	$ —
Receivables	22	8
Inventories	1	—
Total current assets acquired	31	8
Property, plant and equipment	822	248
Total assets acquired	$ 853	$ 256
Current liabilities:		
Accounts payable	78	23
Total current liabilities assumed	78	23
Asset retirement obligations	7	1
Total liabilities assumed	85	24
Net assets acquired	$ 768	$ 232

2011

During the fourth quarter of 2011, we closed a series of transactions in the Eagle Ford shale that were accounted for as a business combination. The most significant of these transactions was the acquisition of Hilcorp Resources, LLC. The total cash consideration paid for all the transactions including approximately 167,000 net acres and a gathering system, was $4.5 billion which was funded from existing cash.

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

(In millions)

Current assets:		
Receivables	$	40
Inventories		4
Other current assets		30
Total current assets acquired		74
Property, plant and equipment		4,501
Other noncurrent assets		21
Total assets acquired	$	4,596
Current liabilities:		
Accounts payable	$	101
Other current liabilities		20
Total current liabilities assumed		121
Asset retirement obligations		5
Total liabilities assumed		126
Net assets acquired	$	4,470

In addition, during 2011,our E&P segment acquired approximately 108,000 net acres in the Eagle Ford shale for approximately $265 million. These transactions were funded from existing cash and were accounted for as asset acquisitions.

Variable Interest Entities	12 Months Ended Dec. 31, 2012
Variable Interest Entities Disclosure [Abstract]	
Variable Interest Entities	**Variable Interest Entities** The owners of the AOSP, in which we hold a 20 percent undivided interest, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with a $3 million current liability recorded at December 31, 2012, consistent with December 31, 2011. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a variable interest entity ("VIE"). We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore the Corridor Pipeline is not consolidated by Marathon Oil. Our maximum exposure to loss as a result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $694 million as of December 31, 2012. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month’s activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

Derivatives	**12 Months Ended Dec. 31, 2012**
Derivatives Disclosure [Abstract]	
Derivatives	

Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 15. See Note 1 for discussion of the types of derivatives we use and the reasons for them. The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheet as of December 31, 2012.

	December 31, 2012			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$ 18	$ —	$ 18	Other current assets
Interest rate	21	—	21	Other noncurrent assets
Total Designated Hedges	39	—	39	
Not Designated as Hedges				
Commodity	52	—	52	Other current assets
Total Not Designated as Hedges	52	—	52	
Total	$ 91	$ —	$ 91	

As of December 31, 2011, our only derivatives outstanding were interest rate swaps that are fair value hedges, which had an asset value of $5 million and were located on the consolidated balance sheet in other noncurrent assets.

Derivatives Designated as Fair Value Hedges

As of December 31, 2012 and 2011, we had multiple interest rate swap agreements with a total notional amount of $600 million with a maturity date of October 1, 2017 at a weighted-average, LIBOR-based, floating rate of 4.70 percent and 4.76 percent, respectively.

In connection with the debt retired in February and March 2011 discussed in Note 17, we settled interest rate swaps with a notional amount of $1,450 million. We recorded a $29 million gain, which reduced the loss on early extinguishment of debt.

As of December 31, 2012, our foreign currency forwards had an aggregate notional amount of 3,043 million Norwegian Kroner at a weighted average forward rate of 5.780. These forwards hedge our current Norwegian tax liability and have settlement dates through June 2013.

The following table summarizes the pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income.

		Gain (Loss)		
(In millions)	Income Statement Location	2012	2011	2010
Derivative				
Commodity	Sales and other operating revenues	$ —	$ —	$ (1)
Interest rate	Net interest and other	16	28	26
Interest rate	Loss on early extinguishment of debt	—	29	—
Foreign currency	Provision for income taxes	(1)	—	—
Hedged Item				
Commodity	Sales and other operating revenues	$ —	$ —	$ 1
Long-term debt	Net interest and other	(16)	(28)	(26)
Long-term debt	Loss on early extinguishment of debt	—	(29)	—
Accrued taxes	Provision for income taxes	1	—	—

Derivatives Not Designated as Hedges

In August 2012, we entered into crude oil derivatives related to a portion of our forecasted U.S. E&P crude oil sales through December 31, 2013. These commodity derivatives were not designated as hedges and are shown in the table below.

Remaining Term	Bbls per Day	Weighted Average Price per Bbl	Benchmark

Swaps			
January 2013 - December 2013	20,000	$96.29	West Texas Intermediate
January 2013 - December 2013	25,000	$109.19	Brent
Option Collars			
January 2013 - December 2013	15,000	$90.00 floor / $101.17 ceiling	West Texas Intermediate
January 2013 - December 2013	15,000	$100.00 floor / $116.30 ceiling	Brent

The net gains related to all commodity derivative instruments not designated as hedges appear in the sales and other operating revenues line of our consolidated statements of income and were $70 million, $5 million and $121 million in 2012, 2011 and 2010.

Equity Method Investments and Related Party Transactions (Notes)	12 Months Ended Dec. 31, 2012
Equity Method Investments Disclosure [Abstract]	
Equity Method Investments and Related Party Transactions	

Equity Method Investments and Related Party Transactions

During 2012, 2011 and 2010 only our equity method investees were considered related parties and they included:

- Alba Plant LLC, in which we have a 52 percent noncontrolling interest. Alba Plant LLC processes LPG.
- AMPCO, in which we have a 45 percent interest. AMPCO is engaged in methanol production activity.
- EGHoldings, in which we have a 60 percent noncontrolling interest. EGHoldings is engaged in LNG production activities.

Our equity method investments are summarized in the following table:

	Ownership as of December 31,	December 31,	
(In millions)	2012	2012	2011
EGHoldings	60%	$ 817	$ 875
Alba Plant LLC	52%	264	272
AMPCO	45%	187	191
Other investments		11	45
Total		$ 1,279	$ 1,383

As of December 31, 2012, the carrying value of our equity method investments was $133 million higher than the underlying net assets of investees. This basis difference is being amortized into net income over the remaining estimated useful lives of the underlying net assets.

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $381 million in 2012, $509 million in 2011 and $400 million in 2010.

Summarized financial information for equity method investees is as follows:

(In millions)	2012	2011	2010
Income data – year:			
Revenues and other income	$ 1,330	$ 1,544	$ 1,305
Income from operations	755	942	762
Net income	635	820	671
Balance sheet data – December 31:			
Current assets	$ 607	$ 688	
Noncurrent assets	1,743	2,079	
Current liabilities	395	504	
Noncurrent liabilities	29	115	

Almost all of our purchases from related parties are liquid hydrocarbons acquired from Alba Plant LLC. Approximately 75 percent of our sales to related parties in all periods are associated with sales of natural gas to EGHoldings.

Asset Retirement Obligations (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended	
	Dec. 31, 2012	Dec. 31, 2011
Asset Retirement Obligation, Roll Forward Analysis [Roll Forward]		
Asset Retirement Obligation Beginning Balance	$ 1,510	$ 1,355
Incurred, including acquisitions	150	37
Settled, including dispositions	(35)	(39)
Accretion expense (included in depreciation, depletion and amortization)	91	81
Revisions to previous estimates	150	126
Held for sale	(83)	0
Spin-off downstream business	0	(50)
Asset Retirement Obligation Ending Balance	1,783 [1]	1,510
Asset Retirement Obligation, Current	$ 34	

[1] Includes asset retirement obligations of $34 million classified as a short-term at December 31, 2012.

Segment Information	**12 Months Ended Dec. 31, 2012**
Segment Information Disclosure [Abstract]	
Segment Information	

Segment Information

We have three reportable operating segments. Each of these segments is organized and managed based upon the nature of the products and services they offer.

- E&P – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- OSM – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.
- IG – produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations, net of income taxes, attributable to the operating segments. Our corporate general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities, net of associated income tax effects. Impairments, gains or losses on disposal of assets, unrealized gains or losses on crude oil derivative instruments or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

As discussed in Note 3, our downstream business was spun-off on June 30, 2011 and has been reported as discontinued operations for 2011 and 2010. Sales to MPC previously reported as Intersegment revenues are reported as Customer revenues because such sales are expected to continue subsequent to the spin-off. Such sales were $1.4 billion in the first six months of 2011, and $1.8 billion in 2010.

Differences between segment totals and our consolidated totals for income taxes and depreciation, depletion and amortization represent amounts related to corporate administrative activities and other unallocated items which are included in "Items not allocated to segments, net of taxes" in the reconciliation below. Capital expenditures include accruals but not corporate administrative activities.

(In millions)	E&P	OSM	IG	Total
2012				
Revenues:				
Customer	$ 14,026	$ 1,552	$ —	$ 15,578
Related parties	58	—	—	58
Segment revenues	$ 14,084	$ 1,552	$ —	15,636
Unrealized gain on crude oil derivative instruments				52
Total revenues				$ 15,688
Segment income	$ 1,881	$ 176	$ 91	$ 2,148
Income from equity method investments	238	—	132	370
Depreciation, depletion and amortization	2,226	217	—	2,443
Income tax provision	4,741	59	27	4,827
Capital expenditures	4,835	188	2	5,025

(In millions)	E&P	OSM	IG	Total
2011				
Revenues:				
Customer	$ 12,922	$ 1,588	$ 93	$ 14,603
Intersegment	47	—	—	47
Related parties	60	—	—	60
Segment revenues	$ 13,029	$ 1,588	$ 93	14,710
Elimination of intersegment revenues				(47)
Total revenues				$ 14,663
Segment income	$ 2,157	$ 256	$ 178	$ 2,591
Income from equity method investments	249	—	213	462

Depreciation, depletion and amortization	2,028	196	3	2,227
Income tax provision	2,808	82	74	2,964
Capital expenditures	3,038	308	2	3,348

(In millions)	E&P	OSM	IG	Total
2010				
Revenues:				
Customer	$ 10,651	$ 833	$ 150	$ 11,634
Intersegment	75	—	—	75
Related parties	56	—	—	56
Segment revenues	$ 10,782	$ 833	$ 150	11,765
Elimination of intersegment revenues				(75)
Total revenues				$ 11,690
Segment income (loss)	$ 1,941	$ (50)	$ 142	$ 2,033
Income from equity method investments	188	—	181	369
Depreciation, depletion and amortization	1,911	105	2	2,018
Income tax provision (benefit)	2,266	(12)	73	2,327
Capital expenditures	2,474	874	2	3,350

The following reconciles total revenues to sales and other operating revenues in the consolidated statements of income.

(In millions)	2012	2011	2010
Total revenues	$ 15,688	$ 14,663	$ 11,690
Less: Sales to related parties	58	60	56
Sales and other operating revenues	$ 15,630	$ 14,603	$ 11,634

The following reconciles segment income to net income as reported in the consolidated statements of income.

(In millions)	2012	2011	2010
Segment income	$ 2,148	$ 2,591	$ 2,033
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(441)	(317)	(170)
Impairments	(231)	(195)	(286)
Gain on dispositions	72	45	407
Unrealized gain on crude oil derivative instruments	34	—	—
Loss on early extinguishment of debt	—	(176)	(57)
Tax effect of subsidiary restructuring	—	(122)	—
Deferred income tax items	—	(61)	(45)
Water abatement - Oil Sands	—	(48)	—
Eagle Ford transaction costs	—	(10)	—
Income from continuing operations	1,582	1,707	1,882
Discontinued operations	—	1,239	686
Net income	$ 1,582	$ 2,946	$ 2,568

Revenues from external customers are attributed to geographic areas based upon selling location. The following summarizes revenues from external customers by geographic area.

(In millions)	2012	2011	2010
United States	$ 6,442	$ 6,971	$ 5,363
United Kingdom	1,245	1,546	1,063
Libya[(a)]	1,989	216	1,473
Norway	3,582	3,386	2,243
Canada	1,552	1,588	833
Other international	878	956	715
Total revenues	$ 15,688	$ 14,663	$ 11,690

[(a)] See Note 13 for discussion of Libya operations.

In 2012, Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 15 percent of our total revenues, while sales to Shell Oil and its affiliates accounted for approximately 12 percent of total revenues. In 2011 and 2010, our sales to MPC accounted for approximately 18 percent and 16 percent of total revenues. In 2010, sales to the Libyan National Oil Company accounted for approximately 13 percent of total revenues.

Revenues by product line were:

(In millions)	2012	2011	2010
Liquid hydrocarbons	$ 12,945	$ 11,717	$ 9,480
Natural gas	1,103	1,291	1,295
Synthetic crude oil	1,545	1,581	832
Transportation & other	95	74	83
Total revenues	$ 15,688	$ 14,663	$ 11,690

The following summarizes certain long-lived assets by geographic area, including property, plant and equipment and equity investments.

(In millions)	2012	2011
United States	$ 13,677	$ 10,928
Canada	9,693	9,711
Equatorial Guinea	2,081	2,214
Norway	987	1,133
Other international	3,113	2,721
Total long-lived assets	$ 29,551	$ 26,707

Segment Information (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Revenues:			
Customer	$ 15,630	$ 14,603	$ 11,634
Related parties	58	60	56
Total revenues	15,688	14,663	11,690
Segment income	2,148	2,591	2,033
Income from equity method investments	370	462	344
Depreciation, depletion and amortization	2,478	2,266	2,056
Provision for income taxes	4,531	2,720	2,175
Exploration and Production Segment [Member]			
Revenues:			
Customer	14,026	12,922	10,651
Intersegment		47	75
Related parties	58	60	56
Total revenues	14,084	13,029	10,782
Elimination of intersegment revenues		(47)	(75)
Total revenues			
Segment income	1,881	2,157	1,941
Income from equity method investments	238	249	188
Depreciation, depletion and amortization	2,226	2,028	1,911
Provision for income taxes	4,741	2,808	2,266
Capital expenditures	4,835	3,038	2,474
Oil Sands Mining Segment [Member]			
Revenues:			
Customer	1,552	1,588	833
Intersegment		0	0
Related parties	0	0	0
Total revenues	1,552	1,588	833
Elimination of intersegment revenues		0	0
Total revenues			
Segment income	176	256	(50)
Income from equity method investments	0	0	0
Depreciation, depletion and amortization	217	196	105
Provision for income taxes	59	82	(12)
Capital expenditures	188	308	874
Integrated Gas Segment [Member]			
Revenues:			
Customer	0	93	150
Intersegment		0	0
Related parties	0	0	0
Total revenues	0	93	150

Elimination of intersegment revenues		0	0
Total revenues			
Segment income	91	178	142
Income from equity method investments	132	213	181
Depreciation, depletion and amortization	0	3	2
Provision for income taxes	27	74	73
Capital expenditures	2	2	2
Total All Segments [Member]			
Revenues:			
Customer	15,578	14,603	11,634
Intersegment		47	75
Related parties	58	60	56
Total revenues	15,636	14,710	11,765
Unrealized gain on crude oil derivative instruments	52		
Elimination of intersegment revenues		(47)	(75)
Total revenues	15,688	14,663	11,690
Segment income	2,148	2,591	2,033
Income from equity method investments	370	462	369
Depreciation, depletion and amortization	2,443	2,227	2,018
Provision for income taxes	4,827	2,964	2,327
Capital expenditures	$ 5,025	$ 3,348	$ 3,350

Dispositions	**12 Months Ended Dec. 31, 2012**
Dispositions Disclosure [Abstract]	
Dispositions	

Dispositions

2013

In February 2013, we entered an agreement to convey our interest in the Marcellus natural gas shale play to the operator.

2012

Neptune gas plant – In December 2012, we entered into an agreement to sell our our E&P segment's interest in the Neptune gas plant, located onshore Louisiana. The transaction, with a value of $170 million before closing adjustments, closed in February 2013.

Eagle Ford acreage – In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres located outside the core of the Eagle Ford shale, held by our E&P segment, for proceeds of $9 million. A pretax loss of $18 million was recorded.

Indonesia – In May 2012, we executed agreements to relinquish our E&P segment's operatorship of, and participating interests in, the Bone Bay and Kumawa exploration licenses in Indonesia. As a result, we reported a $36 million loss on disposal of assets. Government ratification of the agreements released us from our obligations and further commitments related to these licenses.

Alaska – In April 2012, we entered into agreements to sell all of our E&P segment's assets in Alaska. One transaction closed in 2012 with proceeds and a net gain of $7 million. The second transaction closed in January 2013, for proceeds of $195 million subject to a six-month escrow of $50 million for various indemnities.

Gulf of Mexico pipelines – In January 2012, we closed on the sale of our E&P segment's interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This included our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded.

Assets held for sale in the December 31, 2012 consolidated balance sheet were related to the Neptune gas plant and Alaska dispositions that were pending at that date and included:

(In millions)		
Other current assets	$	50
Other noncurrent assets		248
Total assets	$	298
Deferred credits and other liabilities		83
Total liabilities	$	83

2011

Burns Point gas plant – In December 2011, we sold our E&P segment's 50 percent interest in the Burns Point gas plant, a cryogenic processing plant located in St. Mary Parish, Louisiana, for total consideration of $36 million and a pretax gain of $34 million.

Alaska LNG facility – In September 2011, we sold our IG segment's equity interest in an LNG processing facility in Alaska and a pretax gain on the transaction of $8 million was recorded.

DJ Basin – In April 2011, we assigned a 30 percent undivided working interest in the approximately 180,000 acres then held by our E&P segment in the Niobrara shale play located within the DJ Basin of southeast Wyoming and northern Colorado for total consideration of $270 million, recording a pretax gain of $37 million. We remain operator of this jointly owned leasehold.

2010

Angola – In February 2010, we closed the sale of a 20 percent non-operated interest in our E&P segment's Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. We received net proceeds of $1.3 billion and recorded a pretax gain on the sale of $811 million. We retained a 10 percent non-operated interest in Block 32.

Gudrun – In March 2011, we closed the sale of our non-operated interests in the Gudrun field development and the Brynhild and Eirin exploration areas offshore Norway for net proceeds of $85 million, excluding working capital adjustments. A $64 million pretax loss on this disposition was recorded in the fourth quarter 2010.

Income per Common Share	**12 Months Ended Dec. 31, 2012**
Income Per Common Share Disclosure [Abstract]	
Income per Common Share	**Income per Common Share** Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive. The per share calculations above exclude 10 million, 7 million and 13 million stock options and stock appreciation rights in 2012, 2011 and 2010 that were antidilutive.

Income per Common Share

Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive.

	2012		2011		2010	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,582	$ 1,582	$ 1,707	$ 1,707	$ 1,882	$ 1,882
Discontinued operations	—	—	1,239	1,239	686	686
Net income	$ 1,582	$ 1,582	$ 2,946	$ 2,946	$ 2,568	$ 2,568
Weighted average common shares outstanding	706	706	710	710	710	710
Effect of dilutive securities	—	4	—	4	—	2
Weighted average common shares, including dilutive effect	706	710	710	714	710	712
Per share:						
Income from continuing operations	$ 2.24	$ 2.23	$ 2.40	$ 2.39	$ 2.65	$ 2.65
Discontinued operations	$ —	$ —	$ 1.75	$ 1.74	$ 0.97	$ 0.96
Net income	$ 2.24	$ 2.23	$ 4.15	$ 4.13	$ 3.62	$ 3.61

The per share calculations above exclude 10 million, 7 million and 13 million stock options and stock appreciation rights in 2012, 2011 and 2010 that were antidilutive.

Other Items	12 Months Ended Dec. 31, 2012

Other Items [Abstract]

Other Items

Other Items

Net interest and other

(In millions)	2012	2011	2010
Interest:			
Interest income	$ 13	$ 12	$ 11
Interest expense[a]	(300)	(281)	(375)
Income on interest rate swaps	7	10	26
Interest capitalized	68	151	297
Total interest	(212)	(108)	(41)
Other:			
Net foreign currency gains (losses)	4	24	(21)
Write off of contingent proceeds	—	(7)	(15)
Other	(11)	(16)	2
Total other	(7)	1	(34)
Net interest and other	$ (219)	$ (107)	$ (75)

[a] Excludes $1 million, $10 million and $16 million paid by United States Steel in 2012, 2011 and 2010 on assumed debt.

Foreign currency transactions – Aggregate foreign currency gains (losses) were included in the consolidated statements of income as follows:

(In millions)	2012	2011	2010
Net interest and other	$ 4	$ 24	$ (21)
Provision for income taxes	80	(57)	(1)
Aggregate foreign currency gains (losses)	$ 84	$ (33)	$ (22)

Segment Information (Details 5) (USD $) In Billions, unless otherwise specified	6 Months Ended		12 Months Ended				
	Jun. 30, 2011	Dec. 31, 2010	Dec. 31, 2012 Statoil [Member]	Dec. 31, 2012 Shell Oil [Member]	Dec. 31, 2011 MPC [Member]	Dec. 31, 2010 MPC [Member]	Dec. 31, 2010 Libyan National Oil Company [Member]
Entity-Wide Revenue, Major Customer, Percent [Line Items]							
Entity-Wide Revenue, Major Customer, Percentage			15.00%	12.00%	18.00%	16.00%	13.00%
Crude oil intersegment sales reclass	$ 1.4	$ 1.8					

Supplemental Cash Flow Information (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Operating activities:			
Interest paid (net of amounts capitalized)	$ 225	$ 268	$ 107
Income taxes paid to taxing authorities	4,974	2,893	2,155
Commercial paper:			
Issuances	13,880	421	0
Repayments	(13,680)	(421)	0
Net commercial paper	200	0	0
Noncash investing and financing activities:			
Asset retirement costs capitalized, excluding acquisitions	286	151	207
Change in capital expenditure accrual	191	104	(140)
Liabilities assumed in acquisitions	109	126	0
Debt payments made by United States Steel	$ 20	$ 214	$ 105

Income Taxes (Details) (USD $) In Millions, unless otherwise specified	1 Months Ended	3 Months Ended	12 Months Ended		
	Mar. 31, 2010	Jun. 30, 2011	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Federal					
Current			$ (80)	$ (210)	$ (279)
Deferred			233	(206)	(267)
Total			153	(416)	(546)
State and local					
Current			(23)	24	2
Deferred			47	82	(10)
Total			24	106	(8)
Foreign					
Current			4,844	3,088	2,941
Deferred			(490)	(58)	(212)
Total			4,354	3,030	2,729
Current Income Tax Expense (Benefit)			4,741	2,902	2,664
Deferred Income Tax Expense (Benefit)			(210)	(182)	(489)
Income Tax Expense (Benefit)			4,531	2,720	2,175
Effective Tax Rate Reconciliation [Abstract]					
Statutory rate applied to income from continuing operations before income taxes			35.00%	35.00%	35.00%
Effects of foreign operations, including foreign tax credits			18.00%	6.00%	20.00%
Change in permanent reinvestment assertion			0.00%	5.00%	0.00%
Adjustments to valuation allowances			21.00%	14.00%	(2.00%)
Tax law changes			0.00%	1.00%	1.00%
Effective income tax rate on continuing operations			74.00%	61.00%	54.00%
Tax Adjustments, Settlements, and Unusual Provisions		716			
Foreign Undistributed Earnings		2,046			
United States Tax Credit On Foreign Tax		488			
United Kingdom Supplemental Oil And Gas Tax Rate Previous				20.00%	
United Kingdom Supplemental Oil And Gas Tax Rate Effective March 2011				32.00%	
Other Foreign Tax Expense Benefit				10	
Other State Tax Expense Benefit		32			
Deferred Tax Assets, Tax Deferred Expense, Reserves and Accruals, Asset Retirement Obligations	45				
Deferred tax assets:					
Employee benefits			510	455	[1]
Operating loss carryforwards			368	354	[1]
Foreign tax credits			4,351	3,005	[1]
Other			121	95	[1]

Valuation allowances:			
Federal	(2,067)	(790)	[1]
State, net of federal benefit	(60)	(40)	[1]
Foreign	(210)	(194)	[1]
Total deferred tax assets	3,013	2,885	[1]
Deferred tax liabilities:			
Property, plant and equipment	3,691	3,404	[1]
Investments in subsidiaries and affiliates	840	1,216	[1]
Other	12	41	[1]
Total deferred tax liabilities	4,543	4,661	[1]
Net deferred tax liabilities	$ 1,530	$ 1,776	
Minimum [Member]			
Income Taxes [Line Items]			
Statutory Income Tax rate in Libya		90.00%	

[1] Certain 2011 amounts were reclassified to conform to the current period's presentation.

Segment Information (Details 4) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Revenue from External Customer [Line Items]			
Revenue from External Customers	$ 15,688	$ 14,663	$ 11,690
Liquid hydrocarbons [Member]			
Revenue from External Customer [Line Items]			
Revenue from External Customers	12,945	11,717	9,480
Natural gas [Member]			
Revenue from External Customer [Line Items]			
Revenue from External Customers	1,103	1,291	1,295
Synthetic crude oil [Member]			
Revenue from External Customer [Line Items]			
Revenue from External Customers	1,545	1,581	832
Transportation and other [Member]			
Revenue from External Customer [Line Items]			
Revenue from External Customers	$ 95	$ 74	$ 83

Incentive Based Compensation Plans (Details) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]			
Weighted average exercise price per share	$ 33.52	$ 32.30	$ 30.00
Expected annual dividend yield	2.20%	2.10%	3.20%
Expected life in years	5 years 7 months 6 days	5 years 3 months 6 days	5 years 1 month 6 days
Expected volatility	41.00%	40.00%	43.00%
Risk-free interest rate	1.20%	1.70%	2.20%
End of year weighted average grant date fair value unvested restricted stock	$ 10.86	$ 10.44	$ 8.70
Disclosure of Compensation Related Costs, Share-based Payments [Abstract]			
Share-based Compensation Arrangement by Share-based Payment Award, Number of Shares Authorized	50,000,000		
Share Based Compensation Arrangement By Share Based Payment Award Maximum Award For Options Or Stock Appreciation Rights	2.41		
Share-based Compensation Arrangement by Share-based Payment Award, Compensation Cost	$ 70	$ 65	$ 51
Employee Service Share-based Compensation, Tax Benefit from Compensation Expense	25	23	19
Proceeds from Stock Options Exercised	41	77	12
Employee Service Share-based Compensation, Tax Benefit Realized from Exercise of Stock Options	$ 24	$ 32	$ 11
Stock Option [Member] | Minimum [Member]			
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]			
Share-based Compensation Arrangement by Share Based Payment Award, Award Contractual Period	3 years		
Stock Option [Member] | Maximum [Member]			
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]			
Share-based Compensation Arrangement by Share Based Payment Award, Award Contractual Period	10 years		
Stock Appreciation Rights (SARs) [Member] | Minimum [Member]			
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]			
Share-based Compensation Arrangement by Share Based Payment Award, Award Contractual Period	3 years		

Stock Appreciation Rights (SARs) [Member] | Maximum [Member]	
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]	
Share-based Compensation Arrangement by Share Based Payment Award, Award Contractual Period	10 years
Restricted Stock [Member] | Granted Officer [Member] | Minimum [Member]	
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]	
Share-based Compensation Arrangement by Share-based Payment Award, Award Vesting Period	3 years
Restricted Stock [Member] | Non Officer [Member]	
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]	
Share-based Compensation Arrangement by Share Based Payment Award, Award Annual Vesting Percentage	33.33%
Restricted Stock [Member] | Non Officer [Member] | Minimum [Member]	
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]	
Share-based Compensation Arrangement by Share-based Payment Award, Award Vesting Period	3 years
Common Stock [Member]	
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]	
Share-based Compensation Arrangement by Share-based Payment Award, Award Vesting Period	3 years

Acquisitions (Tables)	12 Months Ended Dec. 31, 2012
Significant Acquisitions Disclosure [Abstract]	
Schedule of Purchase Price Allocation	

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

(In millions)	
Current assets:	
Receivables	$ 40
Inventories	4
Other current assets	30
Total current assets acquired	74
Property, plant and equipment	4,501
Other noncurrent assets	21
Total assets acquired	$ 4,596
Current liabilities:	
Accounts payable	$ 101
Other current liabilities	20
Total current liabilities assumed	121
Asset retirement obligations	5
Total liabilities assumed	126
Net assets acquired	$ 4,470

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

	Acquisition Date	
(In millions)	August 1, 2012	November 1, 2012
Current assets:		
Cash	$ 8	$ —
Receivables	22	8
Inventories	1	—
Total current assets acquired	31	8
Property, plant and equipment	822	248
Total assets acquired	$ 853	$ 256
Current liabilities:		
Accounts payable	78	23
Total current liabilities assumed	78	23
Asset retirement obligations	7	1
Total liabilities assumed	85	24
Net assets acquired	$ 768	$ 232

Leases (Tables)

Leases [Abstract]

Future Minimum Commitments For Capital And Operating Leases Table

12 Months Ended
Dec. 31, 2012

Future minimum commitments for capital lease obligations and for operating lease obligations having initial or remaining noncancellable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2013	$ 1	$ 42
2014	1	36
2015	1	33
2016	1	29
2017	1	21
Later years	24	49
Sublease rentals	—	(2)
Total minimum lease payments	$ 29	$ 208
Less imputed interest costs	(18)	
Present value of net minimum lease payments	$ 11	

Goodwill (Notes)	12 Months Ended Dec. 31, 2012
Goodwill Disclosure [Abstract]	
Goodwill	

Goodwill

Goodwill is tested for impairment on an annual basis, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill has been reduced below the carrying value. We performed our annual impairment tests during 2012, 2011 and 2010 and no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value appreciably; however, should market conditions deteriorate or commodity prices decline significantly, an impairment may be necessary.

The changes in the carrying amount of goodwill for the years ended December 31, 2012 and 2011 were as follows:

(In millions)	E&P	OSM	Downstream business	Total
2011				
Beginning balance, gross	$ 537	$ 1,412	$ 843	$ 2,792
Less: accumulated impairment	—	(1,412)	—	(1,412)
Beginning balance, net	537	—	843	1,380
Contingent consideration adjustment	—	—	(3)	(3)
Purchase price adjustment	—	—	9	9
Dispositions	(1)	—	(2)	(3)
Spin-off downstream business	—	—	(847)	(847)
Ending balance, net	536	—	—	536
2012				
Beginning balance, gross	536	1,412	—	1,948
Less: accumulated impairments	—	(1,412)	—	(1,412)
Beginning balance, net	536	—	—	536
Dispositions	(11)	—	—	(11)
Ending balance, net	$ 525	$ —	$ —	$ 525

Supplemental Cash Flow Information	12 Months Ended Dec. 31, 2012

Supplemental Cash Flow Information [Abstract]

Supplemental Cash Flow Information

Supplemental Cash Flow Information

(In millions)	2012	2011	2010
Net cash provided by operating activities included:			
Interest paid (net of amounts capitalized)	$ 225	$ 268	$ 107
Income taxes paid to taxing authorities	4,974	2,893	2,155
Commercial paper:			
Issuances	$ 13,880	$ 421	$ —
Repayments	(13,680)	(421)	—
Net commercial paper	$ 200	$ —	$ —
Noncash investing and financing activities:			
Additions to property, plant and equipment			
Asset retirement costs capitalized, excluding acquisitions	$ 286	$ 151	$ 207
Change in capital expenditure accrual	191	104	(140)
Liabilities assumed in acquisitions	109	126	—
Debt payments made by United States Steel	20	214	105

Incentive Based Compensation Plans (Details 4-Restricted) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Awards			
Beginning year unvested restricted stock	3,703,978		
Granted restricted stock	2,202,774		
Vested restricted stock	(1,254,320)		
Forfeited restricted stock	(474,548)		
End of year unvested restricted stock	4,177,884	3,703,978	
Weighted Average Grant Date Fair Value			
Beginning year weighted average grant date fair value unvested restricted stock	$ 25.88	$ 23.03	
Granted restricted stock weighted average grant date fair value restricted stock	$ 31.59		
Vested restricted stock weighted average grant date fair value restricted stock	$ 24.90		
Forfeited restricted stock weighted average grant date fair value restricted stock	$ 27.26		
End of year weighted average grant date fair value unvested restricted stock	$ 29.02	$ 25.88	$ 23.03
Share-based Compensation Arrangement by Share-based Payment Award, Equity Instruments Other than Options, Vested in Period, Total Fair Value	$ 36	$ 30	$ 21
Share Based Compensation Arrangement By Share Based Payment Award Equity Instruments Other Than Options Nonvested Intrinsic Value Amount	$ 94		
Share based compensation arrangement by share based payment award equity instruments other than options nonvested weighted average contractual life	1 year 2 months 11 days		

Defined Benefit Postretirement Plans and Defined Contribution Plan (Tables)

12 Months Ended

Dec. 31, 2012

Defined Benefit Postretirement Plans Disclosure [Abstract]

Schedule of Accumulated Benefit Obligations in Excess of Fair Value of Plan Assets

Summary information for our defined benefit pension plans follows.

	December 31,			
	2012		2011	
(In millions)	U.S.	Int'l	U.S.	Int'l
Projected benefit obligation	$ (1,146)	$ (565)	$ (986)	$ (465)
Accumulated benefit obligation	(937)	(505)	(813)	(418)
Fair value of plan assets	630	500	516	412

Summary Of Defined Benefit Pension Plans With Accumulated Benefit Obligations

The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2012		2011		2012	2011
(In millions)	U.S.	Int'l	U.S.	Int'l		
Change in benefit obligations:						
Benefit obligations at January 1	$ 986	$ 465	$ 3,221	$ 415	$ 301	$ 779
Spin-off downstream business	—	—	(2,308)	—	—	(483)
Service cost	31	19	28	19	4	4
Interest cost	42	22	44	22	14	16
Plan amendment	—	—	—	11	—	—
Actuarial loss	196	49	84	13	8	1
Foreign currency exchange rate changes	—	25	—	(2)	—	—
Benefits paid	(109)	(15)	(83)	(13)	(16)	(16)
Benefit obligations at December 31	$ 1,146	$ 565	$ 986	$ 465	$ 311	$ 301
Change in plan assets:						
Fair value of plan assets at January 1	$ 516	$ 412	$ 1,798	$ 389	$ —	$ —
Spin-off downstream business	—	—	(1,268)	—	—	—
Actual return on plan assets	66	57	30	15	—	—
Employer contributions	157	24	39	23	—	—
Foreign currency exchange rate changes	—	22	—	(2)	—	—
Benefits paid	(109)	(15)	(83)	(13)	—	—
Fair value of plan assets at December 31	$ 630	$ 500	$ 516	$ 412	$ —	$ —
Funded status of plans at December 31	$ (516)	$ (65)	$ (470)	$ (53)	$ (311)	$ (301)
Amounts recognized in the consolidated balance sheet:						
Current liabilities	(17)	—	(17)	—	(19)	(18)
Noncurrent liabilities	(499)	(65)	(453)	(53)	(292)	(283)
Accrued benefit cost	$ (516)	$ (65)	$ (470)	$ (53)	$ (311)	$ (301)
Pretax amounts in accumulated other comprehensive loss:						
Net loss	$ 511	$ 74	$ 432	$ 63	$ 23	$ 16
Prior service cost (credit)	21	10	27	11	(11)	(18)

Schedule Of Net Periodic Benefit Cost And Other Comprehensive Income

Components of net periodic benefit cost and other comprehensive (income) loss – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive (income) loss for our defined benefit pension and other postretirement plans.

	Pension Benefits						Other Benefits		
	2012		2011		2010				
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2012	2011	2010
Components of net periodic benefit cost:									

Service cost	$ 31	$ 19	$ 28	$ 19	$ 30	$ 19	$ 4	$ 4	$ 3
Interest cost	42	22	44	22	47	22	14	16	16
Expected return on plan assets	(43)	(22)	(43)	(23)	(44)	(22)	—	—	—
Amortization:									
- prior service cost (credit)	7	1	6	—	6	—	(7)	(7)	(7)
- actuarial loss	48	4	47	2	48	5	—	—	—
Other	—	—	—	—	—	2	—	—	—
Net settlement loss[a]	45	—	30	—	56	—	—	—	—
Net periodic benefit cost[b]	$ 130	$ 24	$ 112	$ 20	$ 143	$ 26	$ 11	$ 13	$ 12
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)	$ 172	$ 15	$ 97	$ 24	$ 211	$ (25)	$ 7	$ 1	$ 69
Amortization of actuarial (loss) gain	(93)	(4)	(77)	(2)	(167)	(5)	—	—	2
Prior service cost	—	1	—	(11)	—	—	—	—	—
Amortization of prior service credit (cost)	(7)	(1)	(6)	—	(13)	—	7	7	6
Spin-off downstream business [c]	—	—	(24)	—	—	—	—	—	—
Total recognized in other comprehensive (income) loss	$ 72	$ 11	$ (10)	$ 11	$ 31	$ (30)	$ 14	$ 8	$ 77
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 202	$ 35	$ 102	$ 31	$ 174	$ (4)	$ 25	$ 21	$ 89

[a] Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2012, 2011 and 2010.

[b] Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

[c] Includes net inter-company transfers of (gains)/losses due to the spin-off of the downstream business.

Schedule of Assumptions Used

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2012, 2011 and 2010.

	Pension Benefits								
	2012		2011		2010		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2012	2011	2010
Weighted average assumptions used to determine benefit obligation:									
Discount rate	3.44%	4.40%	4.45%	4.70%	5.05%	5.40%	4.06%	4.90%	5.55%
Rate of compensation increase	5.00%	4.50%	5.00%	4.30%	5.00%	5.10%	5.00%	5.00%	5.00%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	4.21%	4.70%	5.05%	5.40%	5.23%	5.70%	4.90%	5.55%	6.85%
Expected long-term return on plan assets	7.75% [a]	5.20%	8.50%	5.86%	8.50%	6.40%	—	—	—
Rate of compensation increase	5.00%	4.30%	5.00%	5.10%	4.50%	5.55%	5.00%	5.00%	4.50%

[a] Effective January 1, 2013, the expected long-term rate of return on plan assets was changed from 7.75 percent to 7.25 percent.

Schedule of Health Care Cost Trend Rates

Assumed health care cost trend rates

	2012	2011	2010
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	8.00%	7.50%	7.50%
Post-65	7.00%	7.00%	7.00%
Prescription drugs	7.00%	7.50%	7.50%
EGWP subsidy[a]	7.50%	n/a	n/a
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	5.00%	5.00%
EGWP subsidy[a]	5.00%	n/a	n/a

Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2020	2018	2018
Post-65	2018	2017	2017
Prescription drugs	2018	2018	2018
EGWP subsidy[a]	2020	n/a	n/a

[a] An employee group waiver plan ("EGWP") is a group Medicare Part D prescription drug plan. Effective January 1, 2013, we implemented the EGWP as a result of the Patient Protection and Affordable Care Act, which ended tax-free status of retiree drug subsidy programs but increased federal funding to Part D prescription drug plans.

Schedule of Effect of One-Percentage-Point Change in Assumed Health Care Cost Trend Rates

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 2	$ (2)
Effect on other postretirement benefit obligations	$ 35	$ (29)

Fair Value of Defined Benefit Pension Plans Assets

The following table presents the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2012 and 2011.

	December 31, 2012							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 16	$ 1	$ 1	$ —	$ —	$ —	$ 17	$ 1
Equity securities:								
Common stock[a]	312	—	—	—	—	—	312	—
Private equity	—	—	—	—	25	—	25	—
REIT	2	—	—	—	—	—	2	—
Investment trust	—	—	1	—	—	—	1	—
Mutual funds[b]	—	171	—	—	—	—	—	171
Pooled funds[c]	—	—	—	152	—	—	—	152
Fixed income securities:								
U.S. treasury notes	67	—	—	—	—	—	67	—
Exchange traded fund	8	—	—	—	—	—	8	—
Corporate bonds[d]	—	—	96	—	—	—	96	—
Non-U.S. government bonds	—	—	5	—	—	—	5	—
Private placements	—	—	18	—	—	—	18	—
Taxable municipal bonds	—	—	14	—	—	—	14	—
Yankee bonds	—	—	2	—	—	—	2	—
Commingled fund[e]	—	—	28	—	—	—	28	—
Pooled funds[f]	—	—	—	166	—	—	—	166
Real estate[g]	—	—	—	—	23	—	23	—
Other	—	—	—	10	12	—	12	10
Total investments, at fair value	$ 405	$ 172	$ 165	$ 328	$ 60	$ —	$ 630	$ 500

	December 31, 2011							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 12	$ 2	$ —	$ —	$ —	$ —	$ 12	$ 2
Equity securities:								
Investment trust	—	—	7	—	—	—	7	—
Exchange traded fund	324	—	—	—	—	—	324	—
Private equity	—	—	—	—	23	—	23	—
Mutual funds[b]	—	159	—	—	—	—	—	159
Pooled funds[c]	—	—	—	96	—	—	—	96
Fixed income securities:								
Pooled funds[f]	—	—	—	149	—	—	—	149
U.S. treasury notes	92	—	—	—	—	—	92	—

Real estate[g]		—		—		—		—		21		—		21		—
Other[h]		—		—		23		6		14		—		37		6
Total investments, at fair value	$	428	$	161	$	30	$	251	$	58	$	—	$	516	$	412

[a] Includes approximately 60 percent of U.S. and non-U.S. common stocks in the pharmaceuticals, banking, oil and gas, telecommunications, electric, retail, transportation, aerospace/defense, insurance, manufacturing, health care, computer, and financial services sectors. The remaining 40 percent of common stock is held in various other sectors.

[b] Includes approximately 75 percent of investments held in U.S. and non-U.S. common stocks in the financial services, consumer staples, health care, energy, basic materials, industrial goods and services, and leisure sectors and 25 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, FTSE ALL Share 5% Capped Index and MSCI World Index, as defined by the investment policy.

[c] Includes approximately 90 percent of investments held in non-U.S. publicly traded common stocks (specifically Asia Pacific, except Japan, and the U.K.) in the financial, energy, consumer staples, industrial, and materials sectors and the remaining 10 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, MSCI AC Asia Pacific ex Japan Index, FTSE Small Cap Index, and MSCI Emerging Markets Index, as defined by the investment policy.

[d] Includes approximately 70 percent of U.S. and non-U.S. corporate bonds in the banking and finance, news/media, oil and gas, utilities, and health care sectors. The remaining 30 percent of corporate bonds are in various other sectors.

[e] Includes approximately 75 percent of investments held in U.S. and non-U.S. corporate bonds in the consumer discretionary, energy, financial, industrial, telecommunication services, and health care sectors and 25 percent of investments held among various other sectors.

[f] Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financial, corporates, and collateralized asset backed securities and 20 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, as defined by the investment policy.

[g] Includes investments diversified by property type and location. The largest property sector holdings, which represent approximately 70 percent of investments held, are office, hotel, residential, and retail with the greatest percentage of investments made in the U.S. and Asia, which includes the emerging markets of China and India.

[h] U.S. Level 2 includes a receivable for the sale of an investment that closed as of December 31, 2011 but did not cash settle until the next business day.

Schedule of Effect of Significant Unobservable Inputs, Changes in Plan Assets

The following is a reconciliation of the beginning and ending balances recorded for plan assets classified as Level 3 in the fair value hierarchy.

	2012							
(In millions)		Private Equity		Real Estate		Other		Total
Beginning balance	$	23	$	21	$	14	$	58
Actual return on plan assets:								
Realized		2		—		—		2
Unrealized		1		1		(2)		—
Purchases		4		3		—		7
Sales		(5)		(2)		—		(7)
Ending balance	$	25	$	23	$	12	$	60

	2011							
(In millions)		Private Equity		Real Estate		Other		Total
Beginning balance	$	67	$	54	$	31	$	152
Less spin-off of downstream business		(46)		(37)		(17)		(100)
Actual return on plan assets:								
Realized		1		1		—		2
Unrealized		2		1		—		3
Purchases		3		4		—		7
Sales		(4)		(2)		—		(6)
Ending balance	$	23	$	21	$	14	$	58

Schedule of Expected Benefit Payments

Estimated future benefit payments – The following gross benefit payments, which reflect expected future services, as appropriate, are expected to be paid in the years indicated.

	Pension Benefits					
(In millions)		U.S.		Int'l		Other Benefits
2013	$	113	$	12	$	18
2014		114		14		19
2015		114		16		20
2016		112		18		20
2017		114		20		20
2018 through 2022		530		109		101

Equity Method Investments and Related Party Transactions (Tables)	12 Months Ended Dec. 31, 2012

Equity Method Investments Disclosure [Abstract]

Schedule of Equity Method Investments

Our equity method investments are summarized in the following table:

(In millions)	Ownership as of December 31, 2012	December 31, 2012	December 31, 2011
EGHoldings	60%	$ 817	$ 875
Alba Plant LLC	52%	264	272
AMPCO	45%	187	191
Other investments		11	45
Total		$ 1,279	$ 1,383

Income And Balance Sheet Information of Equity Investees Table

Summarized financial information for equity method investees is as follows:

(In millions)	2012	2011	2010
Income data – year:			
Revenues and other income	$ 1,330	$ 1,544	$ 1,305
Income from operations	755	942	762
Net income	635	820	671
Balance sheet data – December 31:			
Current assets	$ 607	$ 688	
Noncurrent assets	1,743	2,079	
Current liabilities	395	504	
Noncurrent liabilities	29	115	

Consolidated Balance Sheets Parentheticals (USD $) In Millions, except Share data, unless otherwise specified	Dec. 31, 2012	Dec. 31, 2011
Consolidated Balance Sheets Parenthetical [Abstract]		
Less accumulated depreciation, depletion and amortization	$ (19,266)	$ (17,248)
Preferred stock, no par value	$ 0	$ 0
Preferred stock, shares authorized	26,000,000	26,000,000
Preferred stock, shares issued	0	0
Preferred stock, shares outstanding	0	0
Common stock, par value per share	$ 1	$ 1
Common stock, shares authorized	1,100,000,000	1,100,000,000
Common stock, shares issued	770,000,000	770,000,000
Common stock, securities exchangeable no par value	$ 0	$ 0
Common stock, securities exchangeable shares authorized	29,000,000	29,000,000
Common stock, securities exchangeable shares issued	0	0
Common stock, securities exchangeable shares outstanding	0	0
Held in treasury, shares	63,000,000	66,000,000

Defined Benefit Postretirement Plans and Defined Contribution Plan (Details 3)	12 Months Ended									0 Months Ended
	Dec. 31, 2012 United States Pension Plans of US Entity, Defined Benefit [Member]	Dec. 31, 2011 United States Pension Plans of US Entity, Defined Benefit [Member]	Dec. 31, 2010 United States Pension Plans of US Entity, Defined Benefit [Member]	Dec. 31, 2012 Foreign Pension Plans, Defined Benefit [Member]	Dec. 31, 2011 Foreign Pension Plans, Defined Benefit [Member]	Dec. 31, 2010 Foreign Pension Plans, Defined Benefit [Member]	Dec. 31, 2012 Other Postretirement Benefit Plans, Defined Benefit [Member]	Dec. 31, 2011 Other Postretirement Benefit Plans, Defined Benefit [Member]	Dec. 31, 2010 Other Postretirement Benefit Plans, Defined Benefit [Member]	Jan. 02, 2013 Subsequent Event [Member] United States Pension Plans of US Entity, Defined Benefit [Member]
Weighted average assumptions used to determine benefit obligation:										
Discount rate	3.44%	4.45%	5.05%	4.40%	4.70%	5.40%	4.06%	4.90%	5.55%	
Rate of compensation increase	5.00%	5.00%	5.00%	4.50%	4.30%	5.10%	5.00%	5.00%	5.00%	
Weighted average assumptions used to determine net periodic benefit cost:										
Discount rate	4.21%	5.05%	5.23%	4.70%	5.40%	5.70%	4.90%	5.55%	6.85%	
Expected long-term return on plan assets	7.75% [1]	8.50%	8.50%	5.20%	5.86%	6.40%	0.00%	0.00%	0.00%	7.25%
Rate of compensation increase	5.00%	5.00%	4.50%	4.30%	5.10%	5.55%	5.00%	5.00%	4.50%	

[1] Effective January 1, 2013, the expected long-term rate of return on plan assets was changed from 7.75 percent to 7.25 percent.

Spin-Off	**12 Months Ended Dec. 31, 2012**
Spin Off Disclosure [Abstract]	
Spin-off of Downstream Business	

Spin-off of Downstream Business

On June 30, 2011, the spin-off of Marathon's downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. On June 30, 2011, stockholders of record as of 5:00 p.m. Eastern Daylight Savings time on June 27, 2011 (the "Record Date") received one common share of MPC stock for every two common shares of Marathon stock held as of the Record Date.

In order to effect the spin-off and govern our relationship with MPC after the spin-off, we entered into a Separation and Distribution Agreement, a Tax Sharing Agreement and an Employee Matters Agreement. The Separation and Distribution Agreement governed the separation of the downstream business, the distribution of MPC's shares of common stock to our stockholders, transfer of assets and intellectual property, and other matters related to our relationship with MPC. The Separation and Distribution Agreement provides for cross-indemnities between Marathon Oil and MPC. In general, we have agreed to indemnify MPC for any liabilities relating to our historical E&P operations, OSM operations and IG operations, and MPC has agreed to indemnify us for any liabilities relating to the historical downstream operations.

The Tax Sharing Agreement governs the respective rights, responsibilities and obligations of Marathon Oil and MPC with respect to taxes and tax benefits, the filing of tax returns, the control of audits and other tax matters. In addition, the Tax Sharing Agreement reflects each company's rights and obligations related to taxes that are attributable to periods prior to and including the separation date and taxes resulting from transactions effected in connection with the separation. In general, under the Tax Sharing Agreement, Marathon Oil is responsible for all U.S. federal, state, local and foreign income taxes attributable to Marathon Oil or any of its subsidiaries for any tax period that begins after the date of the spin-off, and MPC is responsible for all taxes attributable to it or its subsidiaries, whether accruing before, on or after the spin-off. The Tax Sharing Agreement contains covenants intended to protect the tax-free status of the spin-off. These covenants may restrict the ability of Marathon Oil and MPC to pursue strategic or other transactions that otherwise could maximize the values of their respective businesses and may discourage or delay a change of control of either company.

The Employee Matters Agreement contains provisions concerning benefit protection for employees who became MPC employees prior to December 31, 2011, treatment of holders of Marathon stock options, stock appreciation rights, restricted stock and restricted stock units, and cooperation between Marathon Oil and MPC in the sharing of employee information and maintenance of confidentiality. Unvested equity-based compensation awards were converted to awards of the entity where the employee holding them worked post-separation. For vested equity-based compensation awards, employees received both Marathon Oil and MPC awards.

The results of operations of our downstream business have been reported as discontinued operations for 2011 and 2010. The table below shows selected financial information reported in discontinued operations related to the spin-off.

(In millions)	2011	2010
Revenues applicable to discontinued operations	$ 38,602	$ 62,488
Pretax income from discontinued operations	$ 2,012	$ 1,065

Dispositions (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended			1 Months Ended	3 Months Ended	3 Months Ended			1 Months Ended		12 Months Ended	1 Months Ended				1 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2012 Neptune Gas Plant [Member]	Sep. 30, 2012 Eagle Ford Shale Member [Member] acre	May 31, 2012 Indonesia [Member]	Jun. 30, 2012 Alaska Rig [Member]	Dec. 31, 2012 Alaska EP [Member]	Jan. 31, 2013 Alaska EP [Member] Subsequent Event [Member]	Jan. 31, 2012 GOM Pipelines [Member]	Dec. 31, 2011 Burnspoint [Member] Disposed [Member]	Sep. 30, 2011 Alaska LNG [Member]	Apr. 30, 2011 DJ Basin [Member] acre	Feb. 28, 2010 Angola [Member]	Feb. 28, 2010 Angola [Member] Disposed [Member]	Feb. 28, 2010 Angola [Member] Retained [Member]	Mar. 31, 2011 Gudrun [Member]	Dec. 31, 2010 Gudrun [Member]
Dispositions Detail [Line Items]																		
Agreement of Sale of Oil and Gas Property and Equipment				$ 170														
Gas and oil acreages undeveloped and developed net					5,800								180,000					
Proceeds from Sale of Oil and Gas Property and Equipment	467	518	1,368		9		7		195	206	36		270	1,300			85	
Proceeds from Sale of Oil and Gas Property and Equipment, Six Month Escrow									50									
Pretax gain/loss on sale					(18)	(36)	7			166	34	8	37	811				64
Interest Percentage											50.00%		30.00%		20.00%	10.00%		
Assets Held For Sale [Abstract]																		
Other current assets								50										
Other noncurrent assets								248										
Total assets								298										
Deferred credits and other liabilities								83										
Total liabilities								$ 83										

Debt (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012		Jun. 30, 2012	Dec. 31, 2011	
Debt Instrument [Line Items]					
Other Long-term Debt, Noncurrent	$ 6,664	[1]		$ 4,793	[1]
Unamortized Discount	(11)			(10)	
Fair value adjustments	(43)	[2]		(32)	[2]
Amounts due within one year	(184)			(141)	
Total long-term debt due after one year	6,512			4,674	
Debt Immediately Due If Change In Control	385				
Long-term Debt, Fiscal Year Maturity [Abstract]					
2013	184				
2014	71				
2015	1,070				
2016	3				
2017	685				
Senior Unsecured Notes Due 2012 [Member]					
Debt Instrument [Line Items]					
Other Long-term Debt, Noncurrent	0			53	
Debt Instrument, Interest Rate, Stated Percentage	9.375%				
Senior Unsecured Notes Due 2013 [Member]					
Debt Instrument [Line Items]					
Other Long-term Debt, Noncurrent	114			114	
Debt Instrument, Interest Rate, Stated Percentage	9.125%				
Senior Unsecured Notes Due 2015 [Member]					
Debt Instrument [Line Items]					
Other Long-term Debt, Noncurrent	1,000	[3]		0	[3]
Debt Instrument, Interest Rate, Stated Percentage	0.90%	[3]			
Senior Unsecured Notes Due 2017 [Member]					
Debt Instrument [Line Items]					
Other Long-term Debt, Noncurrent	682	[3]		682	[3]
Debt Instrument, Interest Rate, Stated Percentage	6.00%	[3]			
Senior Unsecured Notes Due 2018 [Member]					
Debt Instrument [Line Items]					
Other Long-term Debt, Noncurrent	854	[3]		854	[3]
Debt Instrument, Interest Rate, Stated Percentage	5.90%	[3]			
Senior Unsecured Notes Due 2019 [Member]					
Debt Instrument [Line Items]					
Other Long-term Debt, Noncurrent	228	[3]		228	[3]
Debt Instrument, Interest Rate, Stated Percentage	7.50%	[3]			
Senior Unsecured Notes Due 2022 [A] [Member]					

Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	1,000 [3]		0 [3]
Debt Instrument, Interest Rate, Stated Percentage	2.80% [3]		
Senior Unsecured Notes Due 2022 [B] [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	32		32
Debt Instrument, Interest Rate, Stated Percentage	9.375%		
Series A Notes Due 2022 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	3		3
Senior Unsecured Notes Due 2023 [A] [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	70		70
Debt Instrument, Interest Rate, Stated Percentage	8.50%		
Senior Unsecured Notes Due 2023 [B] [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	131		131
Debt Instrument, Interest Rate, Stated Percentage	8.125%		
Senior Unsecured Notes Due 2032 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	550 [3]		550 [3]
Debt Instrument, Interest Rate, Stated Percentage	6.80% [3]		
Senior Unsecured Notes Due 2037 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	750		750
Debt Instrument, Interest Rate, Stated Percentage	6.60%		
Capital Lease Obligation Due 2012 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	0		9
Sale-leaseback Obligation Due 2012 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	0		11
Capital Lease Obligation of Consolidated Subsidiary due 2013 - 2049 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	11		11
Promissory Note Due 2013 - 2015 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	204		272
Debt Instrument, Interest Rate, Stated Percentage	4.55%		
Obligation Relating To Revenue Bonds Due 2013 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	0	23	23

Debt Instrument, Interest Rate, Stated Percentage	5.375%	5.375%	
Obligation Relating To Revenue Bonds Due 2037 [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	1,000		1,000
Debt Instrument, Interest Rate, Stated Percentage	5.125%		
Other Obligations [Member]			
Debt Instrument [Line Items]			
Other Long-term Debt, Noncurrent	$ 35		$ 0

[1] In the event of a change in control, as defined in the related agreements, debt obligations totaling $385 million at December 31, 2012, may be declared immediately due and payable.

[2] See Note 15 for information on interest rate swaps.

[3] These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

Inventories (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2012	Dec. 31, 2011
Inventory Disclosure [Abstract]		
Liquid hydrocarbons, natural gas and bitumen	$ 73	$ 147
Supplies and sundry items	288	214
Inventories at cost	361	361
Percentage of LIFO Inventory	6.00%	23.00%
Excess of Replacement or Current Costs over Stated LIFO Value	$ 29	$ 74

Defined Benefit Postretirement Plans and Defined Contribution Plan (Notes)	12 Months Ended
	Dec. 31, 2012
Defined Benefit Postretirement Plans Disclosure [Abstract]	
Defined Benefit Postretirement Plans and Defined Contribution Plan	

Defined Benefit Postretirement Plans and Defined Contribution Plan

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Norway and the U.K. Benefits under these plans are based on plan provisions specific to each plan.

We also have defined benefit plans for other postretirement benefits covering our U.S. employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Life insurance benefits are provided to certain retiree beneficiaries. Other postretirement benefits are not funded in advance.

Obligations and funded status – The accumulated benefit obligation for all defined benefit pension plans was $1,442 million and $1,231 million as of December 31, 2012 and 2011.

As of December 31, 2012 and 2011, our U.S. plans and our international plans all have accumulated benefit obligations in excess of plan assets. Summary information for our defined benefit pension plans follows.

	December 31,			
	2012		2011	
(In millions)	U.S.	Int'l	U.S.	Int'l
Projected benefit obligation	$ (1,146)	$ (565)	$ (986)	$ (465)
Accumulated benefit obligation	(937)	(505)	(813)	(418)
Fair value of plan assets	630	500	516	412

The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2012		2011		2012	2011
(In millions)	U.S.	Int'l	U.S.	Int'l		
Change in benefit obligations:						
Benefit obligations at January 1	$ 986	$ 465	$ 3,221	$ 415	$ 301	$ 779
Spin-off downstream business	—	—	(2,308)	—	—	(483)
Service cost	31	19	28	19	4	4
Interest cost	42	22	44	22	14	16
Plan amendment	—	—	—	11	—	—
Actuarial loss	196	49	84	13	8	1
Foreign currency exchange rate changes	—	25	—	(2)	—	—
Benefits paid	(109)	(15)	(83)	(13)	(16)	(16)
Benefit obligations at December 31	$ 1,146	$ 565	$ 986	$ 465	$ 311	$ 301
Change in plan assets:						
Fair value of plan assets at January 1	$ 516	$ 412	$ 1,798	$ 389	$ —	$ —
Spin-off downstream business	—	—	(1,268)	—	—	—
Actual return on plan assets	66	57	30	15	—	—
Employer contributions	157	24	39	23	—	—
Foreign currency exchange rate changes	—	22	—	(2)	—	—
Benefits paid	(109)	(15)	(83)	(13)	—	—
Fair value of plan assets at December 31	$ 630	$ 500	$ 516	$ 412	$ —	$ —
Funded status of plans at December 31	$ (516)	$ (65)	$ (470)	$ (53)	$ (311)	$ (301)
Amounts recognized in the consolidated balance sheet:						

Current liabilities	(17)	—	(17)	—	(19)	(18)
Noncurrent liabilities	(499)	(65)	(453)	(53)	(292)	(283)
Accrued benefit cost	$ (516)	$ (65)	$ (470)	$ (53)	$ (311)	$ (301)
Pretax amounts in accumulated other comprehensive loss:						
Net loss	$ 511	$ 74	$ 432	$ 63	$ 23	$ 16
Prior service cost (credit)	21	10	27	11	(11)	(18)

Components of net periodic benefit cost and other comprehensive (income) loss – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive (income) loss for our defined benefit pension and other postretirement plans.

	Pension Benefits								
	2012		2011		2010		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2012	2011	2010
Components of net periodic benefit cost:									
Service cost	$ 31	$ 19	$ 28	$ 19	$ 30	$ 19	$ 4	$ 4	$ 3
Interest cost	42	22	44	22	47	22	14	16	16
Expected return on plan assets	(43)	(22)	(43)	(23)	(44)	(22)	—	—	—
Amortization:									
- prior service cost (credit)	7	1	6	—	6	—	(7)	(7)	(7)
- actuarial loss	48	4	47	2	48	5	—	—	—
Other	—	—	—	—	—	2	—	—	—
Net settlement loss[a]	45	—	30	—	56	—	—	—	—
Net periodic benefit cost[b]	$ 130	$ 24	$ 112	$ 20	$ 143	$ 26	$ 11	$ 13	$ 12
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)	$ 172	$ 15	$ 97	$ 24	$ 211	$ (25)	$ 7	$ 1	$ 69
Amortization of actuarial (loss) gain	(93)	(4)	(77)	(2)	(167)	(5)	—	—	2
Prior service cost	—	1	—	(11)	—	—	—	—	—
Amortization of prior service credit (cost)	(7)	(1)	(6)	—	(13)	—	7	7	6
Spin-off downstream business [c]	—	—	(24)	—	—	—	—	—	—
Total recognized in other comprehensive (income) loss	$ 72	$ 11	$ (10)	$ 11	$ 31	$ (30)	$ 14	$ 8	$ 77
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 202	$ 35	$ 102	$ 31	$ 174	$ (4)	$ 25	$ 21	$ 89

[a] Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2012, 2011 and 2010.

[b] Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

[c] Includes net inter-company transfers of (gains)/losses due to the spin-off of the downstream business.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2013 are $52 million and $7 million. The estimated net loss and prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2013 are $1 million and $7 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2012, 2011 and 2010.

	Pension Benefits								
	2012		2011		2010		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2012	2011	2010
Weighted average assumptions used to determine benefit obligation:									
Discount rate	3.44%	4.40%	4.45%	4.70%	5.05%	5.40%	4.06%	4.90%	5.55%
Rate of compensation increase	5.00%	4.50%	5.00%	4.30%	5.00%	5.10%	5.00%	5.00%	5.00%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	4.21%	4.70%	5.05%	5.40%	5.23%	5.70%	4.90%	5.55%	6.85%

Expected long-term return on plan assets	7.75% [a]	5.20%	8.50%	5.86%	8.50%	6.40%	—	—	—
Rate of compensation increase	5.00%	4.30%	5.00%	5.10%	4.50%	5.55%	5.00%	5.00%	4.50%

[a] Effective January 1, 2013, the expected long-term rate of return on plan assets was changed from 7.75 percent to 7.25 percent.

Expected long-term return on plan assets

U.S. plan – The overall expected long-term return on plan assets assumption for our U.S. plan is determined based on an asset rate-of-return modeling tool developed by a third-party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan's asset allocation to derive an expected long-term rate of return on those assets. Capital market assumptions reflect the long-term capital market outlook. The assumptions for equity and fixed income investments are developed using a building-block approach, reflecting observable inflation information and interest rate information available in the fixed income markets. Long-term assumptions for other asset categories are based on historical results, current market characteristics and the professional judgment of our internal and external investment teams.

International plans – To determine the overall expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation in our international pension plans to develop the overall expected long-term return on plan assets assumption.

Assumed health care cost trend rates

	2012	2011	2010
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	8.00%	7.50%	7.50%
Post-65	7.00%	7.00%	7.00%
Prescription drugs	7.00%	7.50%	7.50%
EGWP subsidy[a]	7.50%	n/a	n/a
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	5.00%	5.00%
EGWP subsidy[a]	5.00%	n/a	n/a
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2020	2018	2018
Post-65	2018	2017	2017
Prescription drugs	2018	2018	2018
EGWP subsidy[a]	2020	n/a	n/a

[a] An employee group waiver plan ("EGWP") is a group Medicare Part D prescription drug plan. Effective January 1, 2013, we implemented the EGWP as a result of the Patient Protection and Affordable Care Act, which ended tax-free status of retiree drug subsidy programs but increased federal funding to Part D prescription drug plans.

Assumed health care cost trend rates have a significant effect on the amounts reported for defined benefit retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 2	$ (2)
Effect on other postretirement benefit obligations	$ 35	$ (29)

Plan investment policies and strategies

The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plan – Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments are utilized for pension payments, expenses, and other liquidity needs. As such, the plan’s targeted asset allocation is comprised of 65 percent equity securities and high-yield bonds and 35 percent other fixed income securities but may be adjusted to better match the plan's liabilities over time as the funded ratio (as defined by the investment policy) changes.

The plan's assets are managed by a third-party investment manager. The investment manager is limited to pursuing the investment strategies regarding asset mix and purchases and sales of securities within the parameters defined in the investment policy guidelines and investment management agreement. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plans – Our international plans’ target asset allocation is comprised of 70 percent equity securities and 30 percent fixed income securities. The plan assets are invested in eleven separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. Investments are diversified by industry and type, limited by grade and maturity. The use of derivatives by the investment managers is permitted, subject to strict guidelines. The investment managers' performance is measured independently by a third-party asset servicing consulting firm. Overall, investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Fair value measurements

Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2012 and 2011.

Cash and cash equivalents – Cash and cash equivalents include cash on deposit and an investment in a money market mutual fund that invests mainly in short-term instruments and cash, both of which are valued using a market approach and are considered Level 1. The money market mutual fund is valued at the net asset value ("NAV") of shares held. Cash and cash equivalents also include a cash reserve account (a collective short-term investment fund) that is valued using an income approach and is considered Level 2. The underlying assets are usually short-term bonds, discount notes, and commercial paper.

Equity securities – Investments in common stock, an S&P 500 exchange-traded fund, and real estate investment trusts ("REIT") are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. The non-public investment trust is valued using a market approach based on the underlying investments in the trust, which are publicly-traded securities, and is considered Level 2. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

Mutual funds – Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and such prices are Level 1 inputs.

Pooled funds – Investments in pooled funds are valued using a market approach at the NAV of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds are benchmarked against a relative public index. These are considered Level 2.

Fixed income securities – U.S. treasury notes and exchange traded funds are valued at the closing price reported in an active market, and are considered Level 1. Corporate bonds, non-U.S. government bonds, private placements, and yankee bonds are valued using calculated yield curves created by models that incorporate factors such as interest rate, benchmark quote, trade data, dealer quotes, primary and secondary market spread activity, and other market information and are considered Level 2. Taxable municipal bonds are valued using calculated yield curves considering market factors such as benchmark issues, trades, trading spreads between similar issuers or creditors, historical trading spreads over widely accepted market benchmarks, and verified bid information. These assets are considered Level 2. The investment in the commingled fund is valued using a market approach at the NAV of units held, and is considered Level 2. The commingled fund consists mostly of high yield U.S. and non-U.S. corporate bonds. Investment opportunities in this fund are limited to qualified retirement plans and their plan participants. The investment objective of the portfolio is to provide long-term total return in excess of the Barclays U.S. High Yield Bond Index.

Real estate – Real estate investments are valued based on discounted cash flows, comparable sales, outside appraisals, price per square foot or some combination thereof and therefore are considered Level 3.

Other – Other investments are composed of an investment in an unallocated annuity contract, an investment contract with an international insurance carrier, and investments in two limited liability companies (“LLCs") with no public market. The LLCs were formed to acquire timberland in the northwest and other properties. The investment in an unallocated annuity contract is valued using a market approach based on the experience of the assets held in an insurer’s general account. The majority of the general account is invested in a well-diversified portfolio of high-quality fixed income securities, primarily consisting of investment-grade bonds. Investment income is allocated among pension plans participating in the general account based on the investment year method. Under this method, a record of the book value of assets held is maintained in subdivisions according to the calendar year in which the funds are invested. The earnings rate for each of these calendar year subdivisions varies from year to year, reflecting the actual earnings on the assets attributed to that year. Due to the lack of transparency in the use of investment year subdivisions, this asset is considered Level 3. The insurance carrier contract is funded by premiums paid annually by the participating plans and the funds are invested by the insurance carrier in portfolios with different risk profiles (low, medium, high) that can be elected by clients. The majority of the underlying investments consists of a well-diversified mix of non-U.S. publicly traded equity and fixed income securities. This asset is considered Level 2. The values of the LLCs are determined using a cost approach based on historical cost less depletion for timber previously harvested. These assets are considered Level 3.

The following table presents the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2012 and 2011.

	December 31, 2012							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 16	$ 1	$ 1	$ —	$ —	$ —	$ 17	$ 1
Equity securities:								
Common stock[a]	312	—	—	—	—	—	312	—
Private equity	—	—	—	—	25	—	25	—
REIT	2	—	—	—	—	—	2	—
Investment trust	—	—	1	—	—	—	1	—
Mutual funds[b]	—	171	—	—	—	—	—	171
Pooled funds[c]	—	—	—	152	—	—	—	152
Fixed income securities:								
U.S. treasury notes	67	—	—	—	—	—	67	—
Exchange traded fund	8	—	—	—	—	—	8	—
Corporate bonds[d]	—	—	96	—	—	—	96	—
Non-U.S. government bonds	—	—	5	—	—	—	5	—
Private placements	—	—	18	—	—	—	18	—
Taxable municipal bonds	—	—	14	—	—	—	14	—
Yankee bonds	—	—	2	—	—	—	2	—
Commingled fund[e]	—	—	28	—	—	—	28	—
Pooled funds[f]	—	—	—	166	—	—	—	166
Real estate[g]	—	—	—	—	23	—	23	—
Other	—	—	—	10	12	—	12	10
Total investments, at fair value	$ 405	$ 172	$ 165	$ 328	$ 60	$ —	$ 630	$ 500

	December 31, 2011							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 12	$ 2	$ —	$ —	$ —	$ —	$ 12	$ 2
Equity securities:								
Investment trust	—	—	7	—	—	—	7	—
Exchange traded fund	324	—	—	—	—	—	324	—
Private equity	—	—	—	—	23	—	23	—
Mutual funds[b]	—	159	—	—	—	—	—	159
Pooled funds[c]	—	—	—	96	—	—	—	96
Fixed income securities:								
Pooled funds[f]	—	—	—	149	—	—	—	149
U.S. treasury notes	92	—	—	—	—	—	92	—
Real estate[g]	—	—	—	—	21	—	21	—
Other[h]	—	—	23	6	14	—	37	6
Total investments, at fair value	$ 428	$ 161	$ 30	$ 251	$ 58	$ —	$ 516	$ 412

[a] Includes approximately 60 percent of U.S. and non-U.S. common stocks in the pharmaceuticals, banking, oil and gas, telecommunications, electric, retail, transportation, aerospace/defense, insurance, manufacturing, health care, computer, and financial services sectors. The remaining 40 percent of common stock is held in various other sectors.

[b] Includes approximately 75 percent of investments held in U.S. and non-U.S. common stocks in the financial services, consumer staples, health care, energy, basic materials, industrial goods and services, and leisure sectors and 25 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, FTSE ALL Share 5% Capped Index and MSCI World Index, as defined by the investment policy.

[c] Includes approximately 90 percent of investments held in non-U.S. publicly traded common stocks (specifically Asia Pacific, except Japan, and the U.K.) in the financial, energy, consumer staples, industrial, and materials sectors and the remaining 10 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, MSCI AC Asia Pacific ex Japan Index, FTSE Small Cap Index, and MSCI Emerging Markets Index, as defined by the investment policy.

[d] Includes approximately 70 percent of U.S. and non-U.S. corporate bonds in the banking and finance, news/media, oil and gas, utilities, and health care sectors. The remaining 30 percent of corporate bonds are in various other sectors.

[e] Includes approximately 75 percent of investments held in U.S. and non-U.S. corporate bonds in the consumer discretionary, energy, financial, industrial, telecommunication services, and health care sectors and 25 percent of investments held among various other sectors.

[f] Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financial, corporates, and collateralized asset backed securities and 20 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, as defined by the investment policy.

[g] Includes investments diversified by property type and location. The largest property sector holdings, which represent approximately 70 percent of investments held, are office, hotel, residential, and retail with the greatest percentage of investments made in the U.S. and Asia, which includes the emerging markets of China and India.

[h] U.S. Level 2 includes a receivable for the sale of an investment that closed as of December 31, 2011 but did not cash settle until the next business day.

The following is a reconciliation of the beginning and ending balances recorded for plan assets classified as Level 3 in the fair value hierarchy.

	2012			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 23	$ 21	$ 14	$ 58
Actual return on plan assets:				
Realized	2	—	—	2
Unrealized	1	1	(2)	—
Purchases	4	3	—	7
Sales	(5)	(2)	—	(7)
Ending balance	$ 25	$ 23	$ 12	$ 60

	2011			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 67	$ 54	$ 31	$ 152
Less spin-off of downstream business	(46)	(37)	(17)	(100)
Actual return on plan assets:				
Realized	1	1	—	2
Unrealized	2	1	—	3
Purchases	3	4	—	7
Sales	(4)	(2)	—	(6)
Ending balance	$ 23	$ 21	$ 14	$ 58

Cash flows

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $64 million in 2013. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $16 million and $18 million in 2013.

Estimated future benefit payments – The following gross benefit payments, which reflect expected future services, as appropriate, are expected to be paid in the years indicated.

	Pension Benefits		Other Benefits
(In millions)	U.S.	Int'l	
2013	$ 113	$ 12	$ 18
2014	114	14	19
2015	114	16	20
2016	112	18	20
2017	114	20	20
2018 through 2022	530	109	101

Contributions to defined contribution plan – We contribute to a defined contribution plan for eligible employees. Contributions to this plan totaled $25 million, $21 million and $20 million in 2012, 2011 and 2010.

Goodwill (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010
Goodwill [Line Items]			
Beginning balance, gross		$ 1,948	$ 2,792
Less: accumulated impairment		(1,412)	(1,412)
Goodwill [Roll Forward]			
Beginning balance, net	536	1,380	
Contingent consideration adjustment		(3)	
Purchase price adjustment		9	
Dispositions	(11)	(3)	
Spin-off downstream business		(847)	
Ending balance, net	525	536	
Exploration and Production Segment [Member]			
Goodwill [Line Items]			
Beginning balance, gross		536	537
Less: accumulated impairment		0	0
Goodwill [Roll Forward]			
Beginning balance, net	536	537	
Contingent consideration adjustment		0	
Purchase price adjustment		0	
Dispositions	(11)	(1)	
Spin-off downstream business		0	
Ending balance, net	525	536	
Oil Sands Mining Segment [Member]			
Goodwill [Line Items]			
Beginning balance, gross		1,412	1,412
Less: accumulated impairment		(1,412)	(1,412)
Goodwill [Roll Forward]			
Beginning balance, net	0	0	
Contingent consideration adjustment		0	
Purchase price adjustment		0	
Dispositions	0	0	
Spin-off downstream business		0	
Ending balance, net	0	0	
Refining, Marketing and Transportation Segment [Member]			
Goodwill [Line Items]			
Beginning balance, gross		0	843
Less: accumulated impairment		0	0
Goodwill [Roll Forward]			
Beginning balance, net	0	843	
Contingent consideration adjustment		(3)	
Purchase price adjustment		9	

Dispositions	0	(2)
Spin-off downstream business		(847)
Ending balance, net	$ 0	$ 0

Other Items (Tables)	**12 Months Ended Dec. 31, 2012**

Other Items [Abstract]

Schedule Of Net Interest And Other Financing Table

Net interest and other

(In millions)	2012	2011	2010
Interest:			
Interest income	$ 13	$ 12	$ 11
Interest expense[a]	(300)	(281)	(375)
Income on interest rate swaps	7	10	26
Interest capitalized	68	151	297
Total interest	(212)	(108)	(41)
Other:			
Net foreign currency gains (losses)	4	24	(21)
Write off of contingent proceeds	—	(7)	(15)
Other	(11)	(16)	2
Total other	(7)	1	(34)
Net interest and other	$ (219)	$ (107)	$ (75)

[a] Excludes $1 million, $10 million and $16 million paid by United States Steel in 2012, 2011 and 2010 on assumed debt.

Schedule Of Foreign Currency Transactions Table

Foreign currency transactions – Aggregate foreign currency gains (losses) were included in the consolidated statements of income as follows:

(In millions)	2012	2011	2010
Net interest and other	$ 4	$ 24	$ (21)
Provision for income taxes	80	(57)	(1)
Aggregate foreign currency gains (losses)	$ 84	$ (33)	$ (22)

Property, Plant and Equipment	**12 Months Ended Dec. 31, 2012**
Property Plant And Equipment Disclosure [Abstract]	
Property, Plant and Equipment	**Property, Plant and Equipment**

(In millions)	December 31, 2012	 2011
E&P		
United States	$ 23,400	$ 19,679
International	13,523	12,579
Total E&P	36,923	32,258
OSM	10,128	9,936
IG	38	37
Corporate	449	341
Total property, plant and equipment	$ 47,538	$ 42,572
Less accumulated depreciation, depletion and amortization	(19,266)	(17,248)
Net property, plant and equipment	$ 28,272	$ 25,324

In the first quarter of 2011, production operations in Libya were suspended. In the fourth quarter of 2011, limited production resumed. Since that time, average net liquid hydrocarbon sales volumes have increased to pre-conflict levels. We and our partners in the Waha concessions continue to assess the condition of our assets in Libya and uncertainty around sustained production and sales levels remains. As of December 31, 2012, our net property, plant and equipment investment in Libya is approximately $745 million and total proved reserves in Libya are 244 mmboe.

Deferred exploratory well costs were as follows:

(In millions)	December 31, 2012	 2011	 2010
Amounts capitalized less than one year after completion of drilling	$ 388	$ 482	$ 334
Amounts capitalized greater than one year after completion of drilling	229	222	323
Total deferred exploratory well costs	$ 617	$ 704	$ 657
Number of projects with costs capitalized greater than one year after			
completion of drilling	6	5	7

(In millions)	2012	2011	2010
Beginning balance	$ 704	$ 657	$ 829
Additions	731	670	329
Dry well expense	(143)	(268)	(83)
Transfers to development	(629)	(279)	(54)
Dispositions	(46)	(76)	(364)

Ending balance	$ 617	$ 704	$ 657

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2012 are summarized by geographical area below:

(In millions)	
Angola	$ 128
Norway	70
E.G.	22
U.S.	9
Total	$ 229

Well costs that have been suspended for longer than one year are associated with 6 projects. Management believes these projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development.

Angola – Exploration on Angola Block 31 began in 2004, with costs accumulating through 2009. Development alternatives are being evaluated and optimization efforts continue for this block.

Norway – Three offshore Norway development projects had costs incurred from 2009 through 2011. The development plan for Boyla was approved by the Norwegian government in October 2012. This will tie-back to the Alvheim FPSO and development drilling is expected to begin in late 2013. Development options are being evaluated for Caterpillar and drilling on Viper is planned for 2015.

E.G. – The Corona well on Block D offshore E.G. was drilled in 2004, and we acquired an additional interest in the well in 2012. We plan to develop Block D through a unitization with the Alba field, which is expected in late 2013 or early 2014.

U.S. – We incurred drilling costs in the Marcellus natural gas shale play from 2009 through 2010, and were carried in drilling that occurred during 2011. At the end of 2012, our plans were to hold and develop our leasehold position in 2013 by drilling and completing one new well and completing one previously drilled well. In February 2013, we entered an agreement to convey our interest in this asset to the operator.