MARATHON OIL CORP
Form 10-K
February 22, 2013

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

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Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ 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 þ
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 þ 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 þ 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. þ
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 þ 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 þ

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.

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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.

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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

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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

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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.

December 31, 2012	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Europe 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

December 31, 2011	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Europe 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

December 31, 2010	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Europe 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.

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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.

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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.

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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

	December 31,	
(In millions, except per share data)	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

(In millions)	Total Equity of Marathon Oil Stockholders: 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 Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury 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.

MARATHON OIL CORPORATION
Notes to 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.

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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.

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(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

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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	